COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

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| In the Matter of the Petition of Boston Edison Company for Approval of its Third and Fourth Supplements to its Second Long-Range Forecast of Electric Power Needs and Requirements (including the requirements of the Concord Municipal Light Plant and the Electric Division of the Wellesley Board of Public Works) | ) | EFSC 85-12 (Phase II) |

# FINAL DECISION



Robert Shapiro
Hearing Officer
April 2, 1987

On the Decision:

Susan F. Tierney
Brian G. Hoefler

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The Energy Facilities Siting Council ("Siting Council" or "EFSC") hereby approves the demand forecast and rejects the supply plan as presented in the Third and Fourth Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements of Boston Edison Company including the requirements of the Concord Municipal Light Plant and the Electric Division of the Wellesley Board of Public Works.

# I. INTRODUCTION

## A. Description of the Company

Boston Edison Company ("Boston Edison," "BECO," or "the Company") is an investor-owned utility engaged in the generation, purchase, transmission, distribution, bulk power sales, and retail sales of electrical energy. In 1985, Boston Edison provided retail service to 40 cities and towns in the greater Boston metropolitan area and wholesale service to 23 customers, primarily municipal light boards.[1] Total electricity sold in 1986 was 11,685 gigawatthours ("GWh") (Exh. HO-158). BECO's sales account for about 30 percent of the retail electricity sold in Massachusetts. Boston Edison services

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1/Two municipally owned electric utilities, the Concord Municipal Light Plant ("Concord") and the Electric Division of the Wellesley Board of Public Works ("Wellesley"), receive almost all of their power requirements from Boston Edison. Sales to these two municipals in 1986 were expected to account for approximately 2.7 percent of BECO's total sales and 2.5 percent of summer peak load. Given the Company's obligation to supply virtually all of these municipals' power needs (Tr. II, pp. 59-60), their annual requirements and peak demands are included in the Company's forecast of total system demand. Consequently, the Siting Council's review of Boston Edison's demand forecast and supply plan also satisfies our mandate to ensure that Concord and Wellesley have sufficient resources to meet their requirements. Also, the Norwood Municipal Light Board ("Norwood") was a total requirements customer of Boston Edison until November 1, 1985. On that day Norwood began receiving its electricity from another supplier, thereby terminating all purchase agreements with Boston Edison (Exh. HO-3, p. H-1).

a largely urbanized area with a summer-peaking load and a high percentage (54 percent) of retail sales in the commercial sector.

In its review of Boston Edison's previous filing, the Siting Council conditionally approved the Company's demand forecast and supply plan. In re Boston Edison Company, 10 DOMSC 203, 250 (1984). In the conditions attached to that decision, the Siting Council ordered the Company to: (1) justify that its forecast's reliance upon old appliance usage data is appropriate; (2) report on the results of its conservation and load management ("C&LM") programs and integrate their expected long-run effects into its demand forecast; and (3) provide information on the status of its coal conversion and other fuel-diversification projects. The Company complied with all of these conditions, as discussed in Sections II.C.1, III.B., and III.H.

### B. History of the Proceedings

On February 1, 1985, the Company filed the demand portion of its 1985 forecast (Exh. HO-1). On March 1, 1985, the Company filed the supply portion of that forecast (Exh. HO-2). In addition, the Company's supply plan included a proposal to build a 345 kilovolt ("kV") underground transmission line referred to as the Mystic-Golden Hills line (Exh. HO-2). The Company provided notice of the proceeding by publication and posting in accordance with the directions of the Hearing Officer.

On September 11, 1985, the Siting Council held a public hearing in Everett, Massachusetts, to receive comments regarding the proposed Mystic-Golden Hills transmission line. On October 10, 1985, the Hearing Officer issued a Procedural Order allowing the Siting Council to consider the transmission line proposal before reviewing the demand forecast and supply plan portion of the Company's filing. The Hearing Officer designated the facility review as Docket No. 85-12 (Phase I), and designated the review of BECO's demand forecast and supply plan as Docket No. 85-12 (Phase II). On November 18, 1985, the Siting Council conditionally approved the Company's petition to construct the Mystic-Golden Hills line. In re Boston Edison Company, 13 DOMSC 63 (1985).

On January 14, 1986, the Hearing Officer issued a Procedural Order directing the Company to file certain supplemental information in the instant proceeding, in lieu of submitting a complete forecast for 1986. On January 17, 1986, in accordance with the January 14, 1986 Procedural Order, the Company filed: (1) a supplement to its 1985 demand forecast (Exh. HO-3); (2) a detailed description of its planning process entitled "Capacity Planning: An Integrated Process" (Exh. HO-10); and (3) a three-volume report describing its conservation and load management programs entitled "Demand Planning Process: An Analysis of Forty Options" (Exhs. HO-5, HO-6, and HO-8). On February 21, 1986, the Company filed (1) a supplement to its 1985 supply plan (Exh. HO-4) and (2) a report detailing its supply planning process entitled "Long Range Supply Plan" (Exh. HO-9).

On September 9, 1986, the Hearing Officer issued a Notice of Adjudication, establishing October 14, 1986 as the deadline for petitions to intervene as a party and petitions to participate as an interested person. The Company provided notice of the proceeding in accordance with the directions of the Hearing Officer.

On October 10, 1986, the Massachusetts Audubon Society ("Audubon Society") filed a petition to participate as an interested person. The Company did not file an objection to the petition of the Audubon Society. On October 14, 1986, the City of Boston ("the City") filed a motion for an extension of time to intervene. On October 17, 1986, the Hearing Officer granted the City's motion for an extension of time to intervene. On November 3, 1986, the City filed its petition to intervene. On November 12, 1986, BECO filed its response to the City's petition to intervene. In a Procedural Order dated November 14, 1986, the Hearing Officer granted the City's petition to intervene and the Audubon Society's petition to participate as an interested person.

On November 21, 1986, the Siting Council conducted a pre-hearing conference to discuss: (1) the possibility of consolidating the Company's 1987 demand forecast and supply plan in the current proceeding; (2) the Company's objections to certain information requests; and (3) the schedule for the remainder of the proceeding. On December 5, 1986, the Hearing Officer issued a

Procedural Order stating that the Company's amended responses to certain information requests had obviated the necessity of merging the Company's 1987 demand forecast and supply plan with the instant proceeding.

On January 26, 1987, the Siting Council conducted a second pre-hearing conference to discuss: (1) establishing a date for filing the Company's 1987 forecast, as well as future forecasts; and (2) hearing and briefing schedules. At this conference, the Company was directed to address its concerns regarding future filing dates at the evidentiary hearing or in its brief.

Evidentiary hearings were conducted on February 12, February 17, and February 27, 1987. The Company presented four witnesses at the hearings: Robert A. Ruscitto, head of the demand planning division, who testified regarding the Company's conservation and load management programs; Richard S. Hahn, manager of the supply and demand planning department, who testified regarding demand forecasting, supply planning, and conservation and load management programs; Robert J. Cuomo, head of the forecasting and statistical analysis division, who testified regarding demand forecasting; and Jack F. Gurkin, head of the planning division, who testified regarding the Company's transmission and distribution systems. The Hearing Officer entered 168 exhibits in the record, largely composed of the Company's responses to information and record requests. The City entered 17 exhibits in the record.

Pursuant to a briefing schedule established by the Hearing Officer, the City filed its brief on March 11, 1987 ("City Brief"), and the Company filed its reply brief on March 18, 1987 ("BECO Brief").[2]

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2/The Audubon Society did not present oral argument or file a brief.

## II. THE DEMAND FORECAST

### A. Standard of Review

As part of its statutory mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," G.L. c. 164, sec. 69H, the Siting Council determines whether "projections of the demand for electric power ... are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. To ensure that the foregoing standard is met, the Siting Council applies three standards to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if the results can be evaluated and duplicated by another person given the same level of technical resources and expertise. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility producing it. A forecast is reliable if the methodology instills confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. In re Boston Edison Company, 10 DOMSC 203, 209 (1984).

### B. Demand Forecast Results

Boston Edison's two most recent demand forecasts have been reviewed in this proceeding -- one filed in February 1985 ("1985 Forecast") and one filed in January 1986 ("1986 Forecast") (Exhs. HO-1, HO-2, HO-3, and HO-4). The Siting Council has focused its review on the data and projections presented in the 1986 Forecast.

Table 1 summarizes key results of Boston Edison's 1986 demand forecast.[3] The Company expects its territory energy demand

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3/The 1986 Forecast projects requirements for the time period from 1986 to 2000. Since the Siting Council's enabling statute only requires electric companies to file forecasts (footnote continued)

(excluding losses) to grow at a compound rate of 2.2 per cent per year over the forecast period and its summer peak demand to rise 1.7 percent annually[4] (Exh. HO-3, p. K-9).

## C. Evaluation of the Demand Forecast

Since much of the Company's forecasting methodology has remained unchanged since the Siting Council approved that methodology in 1984, the Siting Council focuses its discussion here on: (1) the Company's compliance with the two conditions relative to the Company's demand forecast which were imposed by the Siting Council in its last decision; and (2) significant changes in the Company's methodology, data, and assumptions.

### 1. Compliance with Previous Demand Forecast Conditions

#### a. Appropriateness of EEI Data

In its most recent review of a BECO forecast filing, the Siting Council ordered Boston Edison to evaluate whether basing its appliance usage estimates on nationwide data collected by the Edison Electric Institute ("EEI") from as far back as 1971 continued to be appropriate.[5] The Company has provided evidence that it is

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(footnote continued) covering a ten-year time frame (G.L. c. 164, sec. 69I), the Siting Council has limited its evaluation to the time period from 1986 to 1995 ("forecast period"). Still, the Siting Council supports the Company's practice of preparing a forecast in excess of ten years.

4/Boston Edison is a summer peaking system. Although the 1985 Forecast projected a switchover to winter peaking by 1995 (Exh. HO-1, p. H-11), the 1986 Forecast indicates that Boston Edison now expects to remain a summer peaking system through 2000 (Exh. HO-3, p. K-11).

5/The issue of the appropriateness of EEI appliance data had been raised by the Siting Council as far back as 1982 in EFSC 81-12. In re Boston Edison Company, 7 DOMSC 93, 130-131 (1982).

undertaking two efforts to compile territory-specific appliance usage data for possible use in the residential forecast (Tr. II, p. 70).

In one of these projects, the Company has a residential appliance metering study that began in 1985 with a pilot test of 72 Boston Edison employees. The results of this pilot test were used to design a full-scale, year-long metering program which began in the summer of 1986 and should be completed by December 1987 (Exh. HO-3, p. E-4; Exh. HO-102). In the second project, the Company is participating with five other Massachusetts electric companies in a "Joint Utility Metering Project" ("JUMP") designed to meter directly the electricity usage levels and patterns of a sample of residential customers in each utility's service territory. This project is expected to yield data starting in December 1987 (Exh. HO-3, p. E-4).

The Company states that until the results of these studies are available, the EEI data are the best available to the Company (Exh. HO-102). The Company also reports it is unaware of any analysis suggesting that territory-specific usage would be significantly different from that reflected in nationwide data (Exh. HO-102). BECO reported on the results of a nationwide survey EEI conducted in 1982 to review industry research completed since 1977 on residential appliance consumption. According to BECO, this survey indicated that usage estimates (with the exception of those for microwave ovens) had not changed significantly and therefore EEI's 1971 data should remain unchanged (Exh. HO-3, p. E-4; Exhs. HO-102 and HO-129). In addition, the Company said it found that data from other sources, such as the Association of Home Appliance Manufacturers, Commonwealth Electric Company, Stone and Webster, and New England Power Pool ("NEPOOL"), are consistent with the EEI values (Exh. HO-102).

The Siting Council is satisfied that the Company is making progress toward obtaining territory-specific residential end-use data. The Siting Council finds that the recent survey conducted by EEI lends support to the Company's assertion that EEI's nationwide annual usage estimates are reasonable for BECO. While the EEI estimates are neither an ideal nor acceptable long-term data source, the data serve as an acceptable interim source while territory-specific data are accumulated. Further, in light of the evidence provided regarding

BECO's efforts to collect data through its own appliance metering study and through it participation in the JUMP study, the Siting Council finds that the Company is working to develop a reliable appliance consumption database for future forecasts and therefore has complied with the condition as set forth in the last decision.

b. Demand Management Application

In its 1984 decision, the Siting Council also ordered Boston Edison to prepare a report on the results of its demand management programs and to integrate the projected effects of those programs into its demand forecasts. The Company provided such information in detailed documentation and testimony (Exh. HO-3. pp. E-7, F-9, F-10, G-9, I-1 through I-7; Exh. HO-5, pp. 23-110; Exhs. HO-6, HO-7, HO-8, and HO-10; Tr. I, p. 65). The Company has adjusted its "natural" forecast of energy and peak load demand for the effects the Company expects to realize as a result of time-of-use rates ("TOUR") and Company-sponsored conservation and load management (Exh. HO-3, pp. E-23, F-27, G-11, I-32, J-19, J-22, and K-11). Accordingly, the Siting Council finds that Boston Edison has complied with this condition as set forth in the last decision.[6]

A comprehensive discussion of the Siting Council's evaluation of the Company's demand-management efforts is presented in Section III.G., infra.

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6/ In its 1986 filing, BECO complied with the Siting Council's previous order that the Company incorporate demand-management impacts into the results of the Company's long-range demand forecast. In its brief, BECO requested that the Siting Council reconsider imposing this requirement in subsequent filings: "[G]iven the treatment of conservation and load management programs as a 'supply' option, and the desirability of evaluating those programs on a parallel basis with other 'supply' resources, there is good reason to have a load forecast which has some degree of neutrality with respect to the choice of option[s] which will be used to meet the forecasted load" (BECO Brief, p. 11). The Siting Council agrees with the Company on this issue and directs the Company to present in its next forecast filing a demand forecast unadjusted for Company-sponsored C&LM programs and to use that unadjusted forecast in developing the Company's resource plans.

2. Methodological/Data Changes

Boston Edison's 1985 and 1986 Forecasts provide extensive, detailed documentation on the methods, data, and assumptions the Company used to develop those long-range demand forecasts (Exhs. HO-1 and HO-3). The Company explained a number of changes it introduced into its forecasting approach since the previous Siting Council review in 1984.

These changes include: a new econometric model to forecast various types and levels of employment in the Company's service territory, the results of which were used in forecasting energy use in the commercial and industrial sectors (Exh. HO-3, section D); a respecification of a migration model for the territory, the results of which are integrated with an estimate of natural population change to produce an estimate of the number of households in Boston Edison's service territory (Exh. HO-3, pp. C-4 to C-6); respecification of the regression models used to forecast the energy use of various SIC-coded industrial subgroups (Exh. HO-3, section G); integration of the effects the Company expects will result from price-induced and Company-sponsored demand-management programs into the demand forecasts of the residential, commercial, and industrial sectors (Exh. HO-3, pp. E-23, F-27, G-11, I-32, J-19, J-22, K-11); the use of the "HELM" hourly load model to forecast peak demand and to assess the impacts on demand of C&LM programs and TOUR (Exh. HO-3, section I); and analyses to determine the sensitivity of forecast results to changes in the assumptions regarding such variables as economic growth, electricity price, and weather, along with the development of a confidence interval around the Company's "baseline" forecast (Exh. HO-3, section J; Tr. II, pp. 54-57, 77-81; BECO Brief, p. 10[7]).

The Siting Council notes that many of these modifications, such as the respecification of the industrial regression equations, the

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7/In its brief, BECO cites several additional enhancements (BECO Brief, p. 12).

adoption of an hourly load model, and the preparation of sensitivity analyses, reflect changes encouraged by the Siting Council in previous decisions. In re Boston Edison Company, 10 DOMSC 203, 209-241 (1984). Others, such as refinements in the migration equation and the commercial end-use model and data, as well as the Company's stated intention to develop an industrial end-use forecasting model (Tr. II, pp. 67-69), are results of the Company's own initiatives in improving its demand forecasting.

The Siting Council accepts the methodological and data changes the Company introduced in its 1985 and 1986 forecasts as part of a generally reviewable, appropriate, and reliable forecasting approach.

### 3. Conclusions

Based on the record in this proceeding, the Siting Council finds that the Company has institutionalized a forecasting capability aimed at producing a well-documented, reliable demand forecast and at reducing the technical sources of forecasting error. In fact, the Company's demand forecast filing is exemplary in its level of documentation and could serve as a model for how other companies should document their filings to the Siting Council.

Based on the foregoing, the Siting Council finds that Boston Edison's 1985 and 1986 demand forecasts are based on substantially accurate historical information and reasonable statistical projection methods. The Siting Council also finds that the Company's forecasts are reviewable, appropriate, and reliable and, as developed and presented, provide the Company with a sound basis for making resource planning decisions. Accordingly, the Siting Council hereby unconditionally approves Boston Edison's 1985 and 1986 demand forecasts.

## III. THE SUPPLY PLAN

### A. Standard of Review

In keeping with its mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," G.L. c. 164, sec. 69H, the Siting Council reviews three dimensions of a utility's supply plan: adequacy, diversity, and cost. The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. In re Cambridge Electric Light Company, et al, 12 DOMSC 39, 72 (1985); In re Boston Edison Company, 10 DOMSC 203, 245 (1984). The diversity of supply measures the relative mixture of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, offers lower risks. In re Cambridge Electric Light Company, et al, 15 DOMSC ___, 7 (1986). The Siting Council also evaluates whether a supply plan minimizes the long-run cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. In re Boston Edison Company, 7 DOMSC 93, 146 (1982). The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. In re Cambridge Electric Company, et al, 15 DOMSC __, 10-12, 39-40 (1986). Finally, the Siting Council determines whether utilities treat demand management and power from cogeneration and small power production projects on the same basis as they treat new conventional power facilities and power purchases when those utilities attempt to develop an adequate, diverse, and least-cost supply plan.[8] In re Cambridge

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8/ In 1986, the Massachusetts legislature amended the Siting Council's statute to require the Siting Council to approve a company's long-range forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J.

Electric Light Company, et al, 15 DOMSC ___, 7, 27, 40 (1986).

Further, the Siting Council reviews the supply planning processes utilized by utilities. Recognizing that supply planning is a dynamic process undertaken under evolving circumstances, the Siting Council requires utilities' supply plans to identify, evaluate, and choose from a variety of supply options based on reasonable, appropriate, and documented criteria. A company's consistent and systematic application of such criteria to supply planning decisions indicates that a company is evaluating new supply options in a manner that ensures an adequate supply of least-cost, least-environmental-impact power. These processes and criteria take on added importance when the dynamic nature of the energy generation market and the inherent uncertainty of projections make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast. In re Cambridge Electric Light Company et al, 15 DOMSC ___, 7-9 (1986); In re Fitchburg Gas & Electric Light Company, 13 DOMSC 85, 102 (1985).

The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short-run and long-run. In re Cambridge Electric Light Company, et al., 15 DOMSC ___, 8 (1986).

To establish adequacy in the short run, a company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies. In essence, the company must own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. If a company cannot establish that it can provide adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in drawing upon alternative supplies should necessary projects not develop as originally planned. Id., pp. 8-9, 18-24, and 41. The Siting Council has defined short run as the period of time necessary to place the shortest-lead-time resource under a given company's control in service in a timely and cost-effective manner. The short-run may vary on a company-by-company basis. Id., pp. 8 and 18-19.

To establish adequacy in the long run, a company must demonstrate that its planning processes can identify and fully evaluate a reasonable range of supply options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate energy and power resources over all forecast years. The Siting Council recognizes that the later years of the forecast may offer new, but as yet unknown, resource options which are both reliable and cost-effective. The potential for these new resource options should increase in an electric generating and transmission market that adapts to a higher degree of uncertainty, becomes more competitive, and spawns projects which have shorter lead times. In formulating its standard for adequacy in the long-run, the Siting Council recognizes this new energy environment and affords companies the opportunity to plan for their supplies in a creative and dynamic manner. Id., pp. 9 and 24-31.

B. Previous Supply Plan Reviews

The Siting Council raised two principal concerns regarding Boston Edison's previous supply plan. First, the Company's generation plans relied heavily on oil, and, second, the plan identified capacity shortfalls as early as 1990 but did not propose specific plans to avoid them. In re Boston Edison Company, 10 DOMSC 203, 241 (1984). The Company had indicated its efforts in general to address these issues through fuel diversification, conservation, and load management in its IMPACT 2000 program. Id., p. 249. As a condition to approval of its supply plan, the Company was ordered to present its plans for monitoring and evaluating conservation and load management programs[9] and to keep the Siting Council informed of the status of the Company's coal conversion projects and other approaches to diversifying its fuel mix. Id., pp. 246-247 and 250.

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9/The Company's compliance with this Condition is addressed in Section II.C.1.b., supra.

Since that decision was issued in March 1984, the Siting Council has recognized and embraced a new competitive and dynamic supply environment. As a result, the Siting Council has recently allowed companies to show they have adequate supply plans in the long-run by demonstrating that they have adequate planning processes. Therefore, consistent with the Siting Council's long-run standard outlined in Section III.A., the Siting Council relaxes its previous requirement that the Company prove adequate supplies in the forecast years beyond the short-run.

In regard to Condition 3 of the previous forecast, the Company states that it is no longer planning to convert either the New Boston or the Mystic units to coal at this time (Exhs. HO-65, HO-83). The Siting Council is satisfied that Boston Edison has complied with that part of Condition 3 requiring reports on specific coal conversion projects. Compliance with the remainder of Condition 3 regarding fuel diversity is discussed in Section III.H., infra.

### C. Supply Planning Methodology

Boston Edison describes its supply planning methodology as an iterative process involving generation planning, demand planning, and load forecasting functions (Exh. HO-10, p. 13; Tr. II, pp. 26-29, 71-72; BECO Brief, pp. 14-15). Inputs to the supply planning process include: the Company's load forecast; estimated effects of time-of-use rates and Company-sponsored demand-management; required reserve levels; fuel forecasts; available energy and capacity alternatives; estimated capital costs; actual and assumed operating characteristics; financial assumptions; and high and low bandwidths on key assumptions (load growth, fuel prices) (Exh. HO-10, pp. 13-16).

The Company states that in planning for both annual energy supplies and peak power capacity, it uses these inputs in two major programs to evaluate the data and produce a supply plan. The first program is the Electric Power Research Institute's ("EPRI") Electric Generation Expansion Analysis System model ("EGEAS"); the second is a production costing program developed by General Electric in 1968 which has since been enhanced by the Company as necessary (Exh. HO-10, pp.

17-18). Boston Edison uses EGEAS to develop its base expansion plan and to analyze the sensitivity of key assumptions. The Company states that the primary difference between its production costing program and EGEAS is that its own model uses an hour-by-hour load shape while EGEAS uses a load duration curve. Thus, the Company finds that its own program is more appropriate for calculating the projected avoided costs and marginal costs used in demand planning studies and cogeneration and small power production ("SPP") negotiations (Exh. HO-10, p. 18).

Pursuant to the order of the Massachusetts Department of Public Utilities ("MDPU"), 220 CMR 8.00 et seq., the Company has developed and begun to implement a process to incorporate cost-effective SPP and cogeneration purchase contracts into the Company's resource mix (Exhs. HO-12 and HO-13). Through this process the Company has established: a standard-offer contract; a "supply block" of new capacity the Company expects to need starting on a certain date; a power-purchase price based on the Company's long-run avoided energy and capacity costs that constitutes the ceiling price the Company may pay to SPP's and cogenerators for such power; and an auction process through which prospective developers may bid to receive the long-run energy and capacity payments for power they supply under their contract with Boston Edison (Id.).

To incorporate demand management into the Company's least-cost planning process, the Company has adopted a demand-management planning process which has included: a "needs assessment" of territory-specific end uses that offer the greatest demand-management potential; an identification of 40 specific techniques that have been implemented or studied by utilities elsewhere in the nation and that BECO could use to control customers' energy use and/or peakload demand; development of a methodology to analyze and compare those techniques according to their costs and benefits, where the value of benefits is measured in terms of the Company's long-run marginal energy and capacity cost; a ranking of those measures in terms of their expected net present value and their benefit/cost ratios; selection of a subset of the 40 measures for further risk assessment and for design as pilot programs; proposals to implement a set of six pilots; and current operation of

three programs with six more designated for implementation in 1987. (Exhs. HO-5, HO-6, HO-7, HO-8, HO-9, HO-10, HO-137A, HO-140, HO-153, HO-154, and HO-159; Tr. I, pp. 61-64; Tr. II, pp. 155-157; BECO Brief, pp. 16-19.)

From various analyses based on these assumptions, models, and processes, the Company develops a base expansion plan that meets energy and power requirements. The Company states that this expansion plan serves as its operating plan and as the basis for determining the economics of demand-management and outside supply contracts. BECO states further that sensitivity studies provide the Company with a decision-making plan in the event of changes in its basic assumptions. The Company avers that this process "ensures that the Company will build generation facilities only when they are the most economic resource when compared to other options (supply and demand) on a standard basis" (Exh. HO-10, p. 19).

### D. Supply Plan Results

#### 1. Base Expansion Plan

The Company filed its "Long Range Supply Plan" ("1986 Supply Plan") in February 1986 (Exh. HO-9). The 1986 Supply Plan presents a base plan for generation expansion, sensitivity analysis for high and low load growth rates and high and low fuel price estimates, and an assessment of cogeneration and SPP potential. The base expansion plan for the expected load growth rate and fuel price forecast is presented in Table 2.[10]

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10/BECO notes that it analyzes capacity additions in 100-MW increments to avoid biases due to unit size. However, the Company states that if it were to build a coal, combined-cycle, or any other intermediate class unit, it would most likely build in larger sizes to take advantage of economies of scale. Typical sizes might be on the order of 400 MW for a coal unit and 300 MW for a combined cycle unit. Still, the Company asserts that its supply planning assumption of 100-MW capacity additions is valid because new construction projects involving larger generating units could be undertaken as joint ventures with other utilities (Exh. HO-9, p. 7).

The Company makes a number of assertions about its supply plans (Exh. HO-9, pp. 1-2, 40-41):

- Life extension of existing fossil-fuel units is economical in all scenarios.
- Short- or long-term purchases are sufficiently economical to recommend relying entirely on purchases thereby deferring any Company construction beyond the Siting Council's ten-year planning horizon.
- Combustion turbine and combined cycle generating units are planned for any necessary Company generation. Coal-fired units are only economical in the case of high fuel prices.
- The first generation addition is planned for 1988 in the base plan, but as early as 1987 for the case of high load growth and as late as 1991 for low load growth.
- The capacity mix is generally constant with respect to load growth changes, but very sensitive to fuel price changes.
- The Ocean State Power purchase is economical in all cases.

### 2. Recommended Expansion Plan

While the Company states that its base expansion plan is its operating plan, it also states that it prefers a generation expansion plan different from the base plan. This recommended plan involves no Company construction and instead relies entirely on purchases from cogenerators, small power producers, independent power producers, and other utilities. See Table 3.

Boston Edison states that the recommended plan differs from the base plan in that: (1) BECO should purchase short-term capacity immediately since even though additional capacity is not needed until 1988, fuel savings are sufficient to make purchases economical; (2) the Company should purchase another 100 MW in 1988 and defer Ocean State Power by one year; and (3) the net present value of the recommended plan is $15 million less than the base expansion plan (Exh. HO-9, p. 21).

### 3. Sensitivity Analysis/Contingency Analysis

Boston Edison performed analyses which showed that changes in growth and fuel price assumptions cause changes in the Company's least-cost supply plan. The Company analyzed a total of nine scenarios -- each combination of base, high, and low growth rates and base, high, and low fuel price estimates -- in its 1986 Supply Plan (Exh. HO-9, pp. 18-36). See Table 4.

All of the Company's sensitivity studies also analyzed the impacts on the Company's supply plan associated with loss of either or both of the Company's planned purchases from new but as yet unconstructed supply projects: the Ocean State Power Company combined cycle power plant ("Ocean State" or "OSP") in Rhode Island and the Pt. Lepreau 2 nuclear plant ("PL 2") in New Brunswick.[11]

### 4. Updated Supply Plan

Since Boston Edison's supply plan is continuously evolving, many changes have occurred since the Company's supply plan was filed in February 1986. Therefore, the record in this case includes the Company's supplemental information requests which enables the Siting Council to review supply plan modifications through the close of hearings (February 27, 1987) in this proceeding.

Recent changes in the supply plan include Boston Edison's negotiation of a new 250 MW, five-year purchase agreement with Northeast Utilities ("NU") under which the Company began receiving supplies on November 1, 1986 (Exh. HO-55). An additional 150 MW purchase from NU is under active negotiation (Tr. II, p. 150). Changes also involved the numerous proposals by cogenerators, SPP's,

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11/The Company's original base case included a purchase from Pt. Lepreau 2 even though the Company stated that it assumed PL 2 was "indefinitely deferred" (Exh. HO-9, p. 3). The Company treated loss of PL 2 as a contingency in its sensitivity analysis (Exh. HO-9). The Siting Council will also assume PL 2 is indefinitely deferred.

and independent power producers to sell power and energy to the Company. The Company has signed contracts with eight of those suppliers,[12] the largest of which is the 90 MW (summer capacity[13]) Ocean State purchase. Since those contracts were signed, the Company issued its Request for Proposals ("RFP") soliciting up to 200 MW of cogeneration and SPP to be added by 1991 (Exhs. HO-12 and HO-13). As of the close of hearings in this proceeding, the response to this solicitation was not yet known. One other significant change is NEPOOL's implementation of its Performance Incentive Program ("PIP") (Exh. HO-33). PIP has substantially modified the Company's capability responsibility[14] and established a policy of meeting summer capability responsibility with summer generating unit ratings.

Boston Edison's supply plan is compared to the Company's capability responsibility and summarized in Table 5. The Siting Council will evaluate this supply plan in its determination of adequacy of supply.

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12/Although the Company has signed contracts with eight suppliers, only four of those eight contracts have been approved by the MDPU. Hereinafter, those four contracts are classified as "approved" while the four contracts not yet approved by the MDPU are classified as "likely."

13/Since Boston Edison is a summer peaking system and NEPOOL plans to implement a program for relying on summer capacities during the summer period (Exh. HO-33), the Siting Council will discuss Boston Edison power projects in terms of their summer capacity ratings.

14/For instance, 1988 summer reserve requirements were originally forecast at 13.4 percent (Exh. HO-9, p. 14), but later recalculated at 22.1 percent (Exh. HO-157B) primarily due to PIP implementation.

E. Adequacy of the Supply Plan

In accordance with the Siting Council's previously articulated standard of review, Section III.A., supra, Boston Edison's supply plan is evaluated in terms of its ability to meet resource requirements in both the short run and the long run.

1. Adequacy of Supply in the Short Run

a. Definition of Short Run

A company's short-run forecast period is defined as the time required to implement the first resource under that company's direct control to meet the projected need for new capacity. The Company asserts that its shortest-lead-time resource would be a combustion turbine and that combustion turbines take approximately 3.5 years to place in service (Exhs. HO-57 and HO-75). Accordingly, the Siting Council finds that Boston Edison's short-run period is one to four years (through summer 1990).

b. Short-Run Options

The City contends that the Company has no short-run supply options for meeting any short-run deficiencies (City Brief, p. 25). However, the Company asserts that it would handle any supply deficits by applying its planning process to look at alternatives and evaluate them accordingly (Tr. I, p. 106). Alternatives include a new 76 MW summer capacity (85 MW nominal) combustion turbine ("CT") peaking unit in Walpole, Massachusetts and purchases from other utilities (Tr. I, p. 109; Tr. II, pp. 145-151; BECO Brief, pp. 22-23). The Siting Council will evaluate the Company's options to determine whether it can reasonably rely upon them to meet its short-run deficits.

The Walpole combustion turbine is a Company construction project with an expected lead time from formal site study to start-up of 3.5 years (Exh. HO-57). However, this project falls within the

short run because of an attempt by the Company to "prelicense" the facility by completing all pre-procurement and pre-construction phases prior to establishing a need for the facility in an identified year (Exh. HO-58; Tr. I, pp. 89-90; Tr. II, pp. 114-115). The Company believes prelicensing serves as a "hedge against uncertainties associated with load growth and anticipated future power purchases" (Exh. HO-58).

The Company expects that prelicensing specific facilities at specific sites will reduce the total lead time for each particular facility. In the case of combustion turbines, the Company expects to reduce the lead time from about 3.5 years to about 1.5 years after the time that need for a given facility has been established (Tr. I, p. 89). The Company has estimated that, assuming all necessary permits are obtained by May 1, 1987, the Walpole facility could be available by November 1988 (Exh. HO-78).

Since the Walpole CT is the Company's first attempt at prelicensing, the concept and process has yet to be tested before all permitting agencies. The record in this proceeding neither supports nor refutes the Company's ability to prelicense the Walpole CT so as to enable start-up as early as November 1988. However, for the Siting Council's analysis of the Company's supply plan, the Siting Council finds that it is reasonable to assume that the Walpole CT could be on line by summer 1989.

The Company has also begun internal background work for the prelicensing of a combined cycle ("CC") generating unit. A CC unit could be built in stages, first as a combustion turbine, then later adapted as a combined cycle plant. Staged construction would mean that BECO could begin receiving power as early as 3.5 years after the formal planning process would have begun. However, since the Company could not clearly indicate progress on its schedule for completing prelicensing activities, the Siting Council must conclude that the lead time for the first stage of any CC units remains 3.5 years[15]

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15/The Walpole combustion turbine is being licensed as a combustion turbine only; it cannot be adapted at any later date to operate as a combined cycle plant (Tr. I, p. 108).

(Tr. I, pp. 112-118). Thus, at this time, the Siting Council finds that the Company cannot reasonably rely upon combined cycle plants for contingency plans to meet any short-run capacity needs.

The second short-run alternative is outside purchases -- in particular, a 150 MW purchase from Northeast Utilities. The NU purchase is readily available since it is already on line and planned for retirement unless purchasers are found (Tr. II, pp. 150-151). Mr. Hahn, the Company's supply planning witness, stated that such a purchase would serve as an "insurance policy" against certain contingencies (Tr. II, p. 167). As of February 17, 1987, Boston Edison and NU were in "the final stages" of negotiation (Tr. II, pp. 197-198).

The City argued that, since Mr. Hahn could not state the specific generation characteristics of the 150 MW NU purchase and since Mr. Hahn also indicated that the Company is not relying on this purchase in its analysis, the 150 MW NU purchase should not be considered as a short-run option (City Brief, pp. 19-20). The Siting Council rejects the City's contention that the NU purchase is not a realistic option. According to the Company, the capacity is already available, negotiations have made significant progress, and the cost is within reason (Tr. II, p. 167). Although Mr. Hahn stated that the Company is not yet relying on the 150 MW purchase, he made it clear that short-term purchases are a preferred Company short-run option.

During the course of this proceeding, an application of the Company's planning process emerged. The Company's 1986 supply plan indicated supply deficits in each year beginning in 1988 (Exh. HO-9, p. 14). As required by the Siting Council's standard for short-run adequacy, the Company filed an action plan for addressing these deficits including the necessity of securing a 100 MW short-term purchase for the period 1987-1990 (Exh. HO-9, p. 3). Such a 100 MW purchase would have provided the necessary capacity to meet the projected deficits. The Company further stated that, if it could not negotiate a purchase by year-end 1986, it would proceed with construction of a 100 MW combustion turbine to be in-service by

1988.[16]

The Company did indeed secure a short-term purchase -- the five-year, 250 MW purchase from NU beginning November 1, 1986. The Company's ability to secure that power supply conforms with the Siting Council's intent that companies have both reasonable planning flexibility and adequate supplies.[17] The purchase also lends support to the Company's assertion that it can secure another 150 MW purchase from NU to meet the presently forecasted 1988 and 1989 deficits.

Accordingly, the Siting Council finds that the Company can reasonably rely upon a 150 MW purchase from NU as a short-run option.[18]

Nevertheless, we question the adequacy of the Company's contingency plans in the event that a short-term purchase could not be found; that is, we question the Company's plan to construct a new CT to be in service before the summer of 1988. The first CT that could

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16/The Company deserves to be commended for the clear format it used to present its supply situation, action plans, and contingency plans in Exhibit HO-9.

17/The changes to the Company's supply plan that precipatated deficits despite the 250 MW, short-term NU purchase are primarily increased reserve requirements and decreased summer capacity ratings, both due to PIP implementation (BECO Brief, pp. 22-23).

18/In its decision in EFSC 86-4, the Siting Council ruled that Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company ("COM/Electric") could not reasonably rely on purchase offerings from NU without more concrete evidence of COM/Electric's ability to contract for such offerings. In re Cambridge Electric Light Company, et al., 15 DOMSC ___, 21 (1986). The record in that proceeding showed that COM/Electric was not actively pursuing negotiations and could not provide details of any purchase arrangements. In the instant proceeding, however, Mr. Hahn testified in detail about the Company's on-going negotiations with NU including testimony about availability, pricing, and timing. Thus, the Siting Council finds significant differences in the relative positions of Boston Edison and COM/Electric in securing an NU purchase agreement.

be available, the Walpole CT, could not be in service any earlier than November 1988 (Exh. HO-78). Without an outside purchase, the Company would experience deficits in 1988 even under base conditions.

The Siting Council cannot accept planning flaws that leave companies vulnerable to short-run deficits. However, in this particular case the Company has identified readily available capacity and has shown (albeit only once) that similar capacity can be added in a timely manner. The Siting Council suggests that, in future filings, the Company should file contingency plans that are reasonably practical.

As another short-run option, the Company stated that, if the Seabrook I power plant comes on line, there may be excess capacity from that plant available for purchase from companies such as Eastern Utilities Associates ("EUA") (Tr. I, p. 109; Tr. II, pp. 149-150). However, since EUA "won't have anything to sell until [Seabrook I] comes on line" (Tr. II, p. 149), and substantial uncertainty surrounds the Seabrook I on-line date (Tr. II, p. 199), the Company has not initiated any detailed purchase discussions (Tr. II, p. 149). The City noted that, even if Seabrook I does come on-line within the short run, the Company could not indicate the amount of power that would be available (City Brief, p. 19). In that BECO was unable to provide more specific information on purchase quantities and pricing, or a reasonably clear timetable, the Siting Council finds that the Company failed to establish that Seabrook I capacity could be relied upon as a short-run option.

In its brief, the Company asserts that the substantial uncertainty surrounding an on-line date for Seabrook I has other implications for the adequacy of Boston Edison's supplies in the short run (BECO Brief, p. 23). Since Seabrook I represents a large capacity addition to NEPOOL but not to Boston Edison,[19] start-up of the plant would increase the Company's reserve margin without direct addition of

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19/The Company is not a participant in the Seabrook I power project.

supplies. Therefore, a delay in Seabrook I start-up also delays the Company's increased reserve margin.[20] But since BECO could not possibly be considered to have reasonable control over Seabrook I start-up, the Siting Council finds that such a delay cannot be considered as an option for the Company in meeting any short-run contingencies.[21]

Therefore, the Siting Council finds that the Company has a short-run action plan with two elements: (1) a 76 MW combustion turbine available prior to the summer of 1989; and (2) a 150 MW purchase from NU available prior to the summer of 1987.

c. Base Case Plan/Recommended Plan

Assuming all new supply projects materialize as planned and load growth at base growth rates, Table 5 shows that the Company should have adequate short-run capacity during 1987 and 1990, but may be capacity deficient in 1988 by 94 MW (2.8 percent) and 1989 by 62 MW (1.9 percent). Since the Siting Council requires companies to prove adequate capacity in the short run, Boston Edison must prove it can obtain supplies to avoid the short-run deficits in 1988 and 1989.

The 1988 and 1989 deficits are "in essence ... sole justification" for the 150 MW NU purchase currently under negotiation (Tr. II, p. 197). Such a purchase would more than adequately meet the deficits in each year. If the Company continues to prelicense the Walpole CT, it could be on line in time to meet the 1989 deficit, although it could not be available in time to meet the 1988 deficit. If Seabrook I is delayed beyond the summer of 1989, the Company would

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20/In the event of a Seabrook I delay, the Company's summer peak reserve requirements under a base load growth rate would be unchanged in 1987, and decreased by 94 MW in 1988, 83 MW in 1989, and 72 MW in 1990 (Exhs. HO-157B and HO-157C).

21/Since a Seabrook I delay would affect the Company's capability responsibility, the Siting Council examines those effects where appropriate.

have no deficit in 1988 and a surplus of 21 MW in 1989. Therefore, the Siting Council finds that Boston Edison has sufficient short-run options to meet its short-run base case deficits.

d. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company must also establish that it can meet a reasonable range of contingencies. To evaluate the adequacy of the Company's short-run supply plan, the Siting Council analyzes three contingencies: (1) simultaneous delay of the three largest new supply contracts, (2) a high load growth rate, and (3) loss of Pilgrim capacity credit. A summary analysis of these contingencies is presented in Table 6.

i. Simultaneous Delay of the Ocean State, Northeast Energy, and Everett Energy Projects

By 1990, the Company plans to add three new, relatively large outside supplies totalling 252 MW: Ocean State Power at 90 MW, Northeast Energy Associates ("Northeast Energy" or "NEA") at 82 MW, and Everett Energy Corporation ("Everett Energy") at 80 MW. Of those three projects, only Ocean State has not yet been approved by the MDPU. The Company stated that postponement of all three of these projects beyond the short run is a reasonably likely contingency. The Company, however, has not prepared plans for that particular scenario (Tr. I, pp. 105-106).

If all other independent supply projects progress as expected, postponement of these three projects would cause a capacity shortfall of about 74 MW below the expected 1990 summer peak.[22] One option the Company has for avoiding this deficit is to construct the 76 MW Walpole combustion turbine which would be sufficient to meet this

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22/Since these projects are scheduled for addition after the summer of 1989, 1990 is the only short-run year affected by this contingency.

deficit. Also, the possibility of a 150 MW purchase of NU capacity would more than adequately meet this contingency.

Accordingly, the Siting Council finds that the Company has established that it has an action plan for securing the necessary supplies to meet requirements in the short run in the event of simultaneous delays in the Ocean State, NEA, and Everett Energy projects.

ii. High Load Growth

The Company's short-run supply plan must also be capable of adapting to a higher than expected load growth rate. The Company filed a high load growth forecast in which load would grow at a compound rate of 2.5 percent from 1986 to 2010 compared to a compound growth rate of 1.7 percent in the base case (Exh. HO-9, p. 22). In the short-run, the Company acknowledges need for capacity in every year in order to meet such growth (See Tables 4 and 6).

Table 6 shows that, in 1987 and 1990, the 150 MW NU purchase would be sufficient to meet the need for additional capacity in the high load growth scenario. However, in 1988 and 1989, that purchase could be required to avoid the base case deficits (see Sec. III.E.1.c, supra), so high load growth would require additional capacity beyond the 150 MW NU purchase. If the Walpole CT is also built, the Company still would have 1988 and 1989 shortfalls of 117 MW and 30 MW, respectively. Even assuming a delay in Seabrook I with the associated decrease in the Company's expected reserve margins, the Company could not meet the potential 1988 deficit.

The high load growth contingency plan filed in February 1986 suggested adding three 100 MW combustion turbines, one each in 1987, 1988, and 1989 (Exh. HO-9, p. 33[23]). Yet the Siting Council has

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23/This particular reference is to the case of high load growth under base fuel prices. Due to the drop in world oil prices during the spring of 1986, fuel prices are much closer to the Company's low fuel price forecast (Tr. I, p. 123). However, for high load growth in the short run, the contingency plans under base and low fuel prices are virtually identical (See Table 4).

already found that, since the Company requires 3.5 years to site, license, construct, and prepare a combustion turbine for start-up, the only possible short-run CT option is the Walpole CT which could be on line by the summer of 1989. See Section III.E.1.b, supra. Unless the Company is already pursuing the licensing of three additional CT's, an action not supported by this record, this contingency plan would clearly fail to meet high load growth in the short run.

Although demand management options may have added considerable flexibility into plans for adapting to load growth uncertainties, the Company has not demonstrated an ability to evaluate the cost effectiveness of demand-side options under various load growth scenarios (See Section III.G, infra). Boston Edison's bias toward generation options in its design of its short-run action plan has led the Company to a situation where it must rely on load growth rates lower than its own high growth forecast.[24] This basic flaw in the Company's supply planning process has unnecessarily exposed Boston Edison's customers to possible supply shortages if growth exceeds base expectations.

A company must demonstrate that its supply plan is sufficiently flexible to meet a reasonable range of contingencies. This range of contingencies is not limited to delay or loss of expected supplies, but also includes uncertainties such as changes in load-growth or fuel-price forecasts. Boston Edison has not demonstrated such flexibility.

Accordingly, the Siting Council finds that the Company has failed to establish that it has an action plan capable of securing the necessary supplies in the short run to meet the Company's high load growth forecast.

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24/The City suggested that one of the Company's plans for improving its potential capacity deficits would be to hope for lower than expected peak load growth (City Brief, p. 20). While Mr. Hahn stated that lower than expected load growth would fall into the category of "positive contingencies that are of sufficient magnitude that they could mitigate the problem [of capacity deficits]" (Tr. II, p. 148), the Siting Council does not construe this categorization to be one of the action plans put forth by the Company.

### iii. Loss of Pilgrim Capacity Credit

An issue raised during the proceeding was whether or not the current Pilgrim nuclear power plant shutdown constitutes a contingency. The Company asserted that, since it expects to continue to receive Pilgrim capacity credit until the time Pilgrim resumes generation, no contingency planning is necessary (Exhs. HO-16, HO-17; Tr. I, pp. 147-149). The City of Boston argued that the issue is not whether Pilgrim will remain operable beyond a reasonable doubt, but instead whether there is a reasonable possibility that the Company will not have Pilgrim at its disposal (City Brief, p. 22). The City stated that "BECO should be facing squarely the very real possibility of losing its Pilgrim capacity credit," and that the Siting Council should "recognize that BECO should have put forward ... an action plan for the loss of the Pilgrim capacity credit" (City Brief, p. 21).

To determine the rules governing capacity credit loss, various NEPOOL standards were introduced into the record. Since Pilgrim generation is dispatched by NEPOOL, Pilgrim is subject to NEPOOL Operating Criteria, Rules and Standards ("CRS"). CRS No. 4 (Exh. HO-152) specifies NEPOOL's requirements for the uniform rating and periodic audit of generating capability, and therefore it governs Pilgrim capacity credit (Tr. I, pp. 140-141, 152). Under this CRS, generating units, including Pilgrim, "must regularly achieve claimed capability....Units having unsatisfactory availability will be subject to deratings by the [NEPOOL Operations Committee]" (Exh. HO-152, p. 1). To verify claimed capabilities, NEPOOL conducts capability "demonstrations" (sometimes called audits) for all centrally dispatched generating units in both a summer period and a winter period (Exh. HO-152, p. 3). Failure to demonstrate full capability during two consecutive like demonstration periods results in a derating to a capability "no greater than the highest capability demonstrated in the two (2) like Demonstration Periods" (Exh. HO-152,

p. 12).[25]

Pilgrim last passed such a capability demonstration in the spring of 1986 (Tr. I, p. 135). Thus, Pilgrim has missed passing one summer and one winter capability demonstration. Failure to pass its summer audit by September 15, 1987, the end of the 1987 Summer Demonstration Period, will result in loss of Pilgrim's summer capacity credit during the 1988 Claimed Capability Period; failure to pass its winter audit by February 29, 1988, the end of the 1987-88 Winter Demonstration Period, will result in loss of Pilgrim's winter capacity credit during the 1988-89 Claimed Capability Period. Mr. Hahn acknowledged that he is aware the Company will lose Pilgrim capacity credit if it does not pass its capability demonstrations during the summer of 1987 and the winter of 1987-88 (Tr. I, pp. 138-140).

Mr. Hahn, however, testified that Pilgrim could regain its capacity credit for the summer of 1988 if Pilgrim came back on line as late as May of 1988 (Tr. I, p. 153-154; BECO Brief, p. 23). The Company failed to estalbish that CRS No. 4 supports such an allegation.

While it is unnecessary for the Siting Council to make a determination as to whether or when Pilgrim will return to operation, the possibility of losing Pilgrim capacity credit is a contingency that merits attention in the Company's contingency planning process. Indeed, the Company's most recent estimate of when Pilgrim will resume generation is the end of June 1987 (Tr. I, p. 133), just two and

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25/NEPOOL differentiates between "Claimed Capability Periods" and "Demonstration Periods." These periods are defined in CRS No. 4 as follows:

| | Claimed Capability Periods | Demonstration Periods |
|---|---|---|
| Summer | June 1 - Sept. 30 | July 1 - Sept. 15 |
| Winter | Oct. 1 - May 31 | Nov. 1 - Feb. 28 (29) |

A NEPOOL member must demonstrate its capability during the Demonstration Period and that demonstrated capability is effective during the Claimed Capability Period. (Exh. HO-152, pp. 2-3)

one-half months before a failure to demonstrate Pilgrim's 666.6 MW summer capacity credit[26] would result in loss of that credit during the 1988 summer period.[27] Therefore, the Siting Council finds that the Company should be planning for the contingency of Pilgrim capacity credit loss.

The short-run supply impact of a possible loss of Pilgrim capacity credit is summarized in Table 6. Even under the most optimistic contingency scenario, the Company's current action plan is not adequate to meet the loss of a generating unit as large as Pilgrim. In any short-run year that Pilgrim capacity credit were lost, capacity deficiencies would occur, reaching a deficit of 589 MW in 1988.[28] Applying the Company's short-run action plan options (see Section III.E.1.b, supra) could possibly reduce the 1988 deficit to 439 MW.

The Siting Council cannot expect utilities to routinely maintain enough firm backup capacity to support the sudden loss of a unit as large as Pilgrim. As the Company correctly notes, a regional power pool serves that function to some degree by pooling back-up resources and enabling members to avoid holding extremely large quantities of backup capacity in reserve (Exh. HO-17). Indeed NEPOOL's operating rules provide for granting two full years of capacity credit to those who must suddenly shut down major facilities. It would seem that this two-year period balances a member company's need for time to plan replacement supplies with NEPOOL's need to move back to full and reliable generation capability.

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26/Pilgrim's current summer capacity credit is 666.6 MW (Exh. HO-4, p. I-8). Boston Edison sells 172 MW to other utilities (Exh. HO-48) leaving 494.6 MW that the Company would lose from its supply plan.

27/CRS No. 4 provides for a derating to a capability no greater than the highest capability demonstrated during the last two demonstration periods. Pilgrim has not generated any power since the spring of 1986; thus, the highest demonstrated capability is zero.

28/Although BECO's portion of Pilgrim capacity amounts to 495 MW, the base case deficit in 1988 contributes another 94 MW.

During the course of this proceeding the Company was asked to provide its contingency plans specifically for the possibility that Pilgrim did not come back on line as the Company expected (Exhs. HO-16, HO-17). The Company stated that it had not prepared such plans, would not prepare such plans, and instead deemed delays in the resumption of Pilgrim generation of a year or more as not "sufficiently likely to warrant preparation of a formal plan" (Exh. HO-16).

The Company provided a glimpse of its preparation for a Pilgrim capacity credit loss in the following policy statement:

> If for some reason Pilgrim no longer qualified for capacity credit, the Company would seek short term purchases looking both inside New England and outside of New England. The availability and costs of such purchases are unknown at this time.
>
> It is unlikely that Qualifying Facilities that are not already under contract or in service would be able to come on line in less than 3 - 5 years. The Company could also pursue additional conservation and load management that would not otherwise be cost effective. However, it is unlikely that this would amount to a significant amount in a 3 - 5 year period and certainly not in the 500 MW range.
>
> Barring the availability of sufficient C&LM, additional QF facilities or additional purchases, the Company would in all probability proceed with the licensing and construction of approximately 500 MW of combustion turbine and combined cycle capacity. The minimum lead time would be about 5 years and could conceivably be considerably longer.
>
> Given the magnitude of the capacity lost and the relatively tight capacity situation within NEPOOL as a region, it is unlikely that capacity deficiencies could be avoided, especially in years 1 - 5. (Exh. HO-17)

The Siting Council cannot consider this sort of vague and speculative statement to be either an indication of responsible resource planning or a specific action plan to address the contingency. The Company acknowledges that loss of Pilgrim capacity credit would pose an enormous problem for the Company which, we would assume, lends additional incentive to study such a loss. Sufficient uncertainty surrounds the Company's ability to count on Pilgrim's

capacity credit in the short run to make it imperative that the Company show it is asking and attempting to answer "What would Boston Edison do if..." types of questions.

During testimony Mr. Hahn was asked when the Company itself would find it necessary to develop contingency plans. He stated that when the Company became "convinced it would lose [Pilgrim capacity credit] for a period of time that would be long enough to justify going out and securing a replacement" (Tr. I, p. 141), it would begin looking for replacement supplies. The witness offered no discernable, relevant explanation as to when the Company might be "convinced" that Pilgrim could cause a capacity deficiency prompting the Company to begin developing contingency plans.

The Siting Council cannot accept or abide the Company's rationale for determining that its Pilgrim situation does not yet merit development of a formal contingency action plan. The Company provided no evidence that it has explored in any detailed fashion the consequences of a Pilgrim capacity credit loss. The Company has not even indicated that it is asking "what-if" questions, much less proceeding with the necessary background work for development of contingency plans.

Accordingly, the Siting Council finds that the Company has failed to establish that it has an action plan capable of securing the necessary supplies in the short-run to meet the contingency of loss of Pilgrim capacity credit.

### 2. Adequacy of Supply in the Long-Run

The Company's long-run planning period is the remaining forecast horizon beyond the short run -- from 1991 through 1995. Of these long-run forecast years, the Company indicates summer deficiencies beginning in 1992 (See Table 5).

As previously stated in Section III.A, supra, the Siting Council does not require electric companies to prove adequate supplies in long-run years as long as a company demonstrates that its planning process can identify and fully evaluate a reasonable range of supply options. The ability of Boston Edison's supply planning process to

identify and fully evaluate a reasonable range of supply options is fully discussed from the perspective of least-cost supply planning in Section III.G., _infra_.

### 3. Conclusions on the Adequacy of Supply

In that the Company has failed to establish that it has an action plan capable of securing the necessary supplies in the short-run to meet either (1) its high load growth forecast or (2) the loss of Pilgrim capacity credit, the Siting Council finds that the Company's supply plan fails to ensure adequate resources to meet customer requirements.

F. Adequacy of the Transmission System Planning

1. The Company's Position

a. The Company's Transmission Plans and Planning Process

In its 1985 filing, Boston Edison identified and discussed certain problem areas in its transmission system (Exh. HO-2, App. B). One of these problem areas was described by the Company as the "Northern Tie" problem (Exh. BOS-14, p. 1), which the Company proposed to resolve by constructing a 6.3-mile 345 kV transmission line between the Company's Mystic Station power plant in Everett, and BECO's Golden Hills substation in Saugus (Exh. HO-2, pp. II-2, II-18, App. B). The Company's plan to resolve the Northern Tie problem was the subject of Phase I of the instant proceeding. The Siting Council conditionally approved the Company's petition to construct the Mystic-Golden Hills line (See Section I.B., supra). In re Boston Edison Company, 13 DOMSC 63 (1985).

The Company's 1985 and 1986 filings also identified an "area supply problem" relating to the Company's expectation that Boston Edison's existing and planned transmission system in downtown Boston will be inadequate to meet customer requirements in the event of certain contingencies starting in 1992 (Exh. HO-2, pp. II-19; Exh. HO-4, pp. II-18). The Company stated that this problem would arise that year even assuming the Company were allowed to construct an underground 345 kV transmission line from Mystic Station to a new 345/115 kV substation near the Company's existing Kingston Street substation in the financial district of downtown Boston (Exh. HO-2, pp. II-15, II-16). This "Mystic-Downtown" line[29] was conditionally

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[29]/The 345 kV transmission line approved by the Siting Council in 1977 was actually proposed to run between Mystic Station and a new 345/115 kV substation on Lincoln Street in Boston's financial district. The in-service date for (footnote continued)

approved[30] by the Siting Council in 1977, with the line originally planned for completion by 1985. In 1985, in its decision on Phase I of the instant proceeding, the Siting Council approved a new, 1989 in-service date for the Mystic-Downtown line. In re Boston Edison Company, 13 DOMSC 63, 82 (1985). As of the conclusion of hearings in this proceeding, the line was not yet under construction (Tr. III, p. 14).

At the request of the City of Boston, the Company sponsored a witness, Mr. Gurkin, to testify in regard to BECO's transmission system planning process. According to Mr. Gurkin, the Company's planning process includes: (a) a forecast of substation-specific load growth forecasts prepared by BECO's Forecasting and Statistical Analysis Division,[31] (Tr. III, pp. 10-11, 31-32, 40-45; Exhs. BOS-5, BOS-6); (b) use of load flow studies to analyze the adequacy of the Company's transmission system in response to a range of generation and transmission contingencies (Tr. III, p. 15); (c) identification of problem areas where the transmission system does not perform

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(footnote continued) this line was projected at the time to be 1985. In re Boston Edison Company, 2 DOMSC 58, 60 (1977). Due to the proximity of the originally proposed Lincoln Street substation and the now-planned substation near the existing Kingston Street substation, the Siting Council, in Phase I of this proceeding, considered the Mystic-Lincoln Street line to be the same as the Mystic-Kingston Street line for purposes of the Siting Council's review process. Hereinafter, this line will be referred to as the "Mystic-Downtown" line or the "Mystic-Kingston" line.

30/These conditions required that: (a) by 1978, the Company provide to the Siting Council an updated in-service date for the line; (b) "because type of construction, exact location, and ultimate design have not been finally determined for the above lines, any party or state or local governmental agency may negotiate or enter into agreements with the Company as to matters of final design, engineering, and construction;" and (c) the Company notify the Siting Council of final costs for the project. In re Boston Edison Company, 2 DOMSC 58, 63-63 (1977).

31/This Division of BECO's Supply and Demand Planning Department prepares the Company's short-run and long-run energy and load forecasts (Tr. III, pp. 10-12), as discussed in Section II.

adequately (Tr. III, p. 10); and (d) preparation of analyses evaluating and recommending approaches to resolving specific system performance problems (Id.).

b. The Downtown Boston Transmission Problem

In response to the City's questioning, Mr. Gurkin testified as to the Company's planning specifically with regard to what the Company has identified as the "Downtown Problem" (Tr. III, pp., 19-23, 51; Exh. BOS-14, p. 1), which the Company states it has planned to resolve through installation of the Mystic-Downtown line (Exh. HO-2, pp. II-15 to II-19).

Mr. Gurkin explained that in 1983, the Company first realized that by the late 1980s, if the Company did not reinforce its existing 115 kV transmission system,[32] Boston Edison would have to disconnect (i.e., "shed load" or "black out") customers in parts of downtown Boston at certain peak load periods and under certain generating and transmission conditions[33] (Tr. III, pp. 58-59, 102-103). In May

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32/In 1976, when Boston Edison asked the Siting Council to approve the Mystic-Downtown line, the Company asserted that the line was need to transport to the Boston area the power produced at the then-proposed Pilgrim 2 in Plymouth. The Siting Council approved the need for the line in 1977. In re Boston Edison Company, 2 DOMSC 58, 60, 63 (1977). Construction of the line did not begin thereafter. Mr. Gurkin testified that in 1981, Boston Edison cancelled its plans to construct Pilgrim 2 (Tr. III, pp. 55). He stated that the downtown transmission problem the Company identified in 1983 related to the expected inability of the Company's existing 115 kV transmission system (i.e., without the approved but as-yet unconstructed 345 kV Mystic-Downtown line) to import power southward to Boston from generating sources north of metropolitan Boston (Tr. III, pp. 55-57).

33/This analysis assumed outages of both units of the New Boston powerplant, and a "most reasonable scenario" forecast of load growth in the five principal downtown Boston substations (Tr. III, pp. 44; Exh. BOS-6). This forecast indicated 4-percent growth per year and was based on an analysis of new construction projects planned for downtown Boston; this forecast indicated faster growth than the 1.6-percent annual load growth projection for the entire BECO service territory (Exh. BOS-13).

1984, Boston Edison issued a report indicating that: due to faster than expected load growth, this potential problem could occur as early as 1987/88;[34] and "exposing the core city area to the risk of significant load disconnection two or three times a summer is unacceptable" (Exh. BOS-14, p. 8). The report recommended a plan to resolve the problem (Exh. BOS-14; Tr. III, pp. 58-59) through: (a) installation of phase-angle regulating transformers in 1988; (b) reconductoring existing lines in 1986 and 1987; (c) building a 345/115 kV autotransformer in downtown Boston (near the financial district) in 1988; (d) installing the first cable of a Mystic-Downtown 345 kV transmission line in 1988; and (e) installing a second cable and autotransformer around 1995 (Exh. BOS-14, pp. 1-4).

Mr. Gurkin testified that the first cable of the new Mystic-Downtown transmission line has been authorized by Boston Edison management, but the second has not yet been approved (Tr. III, p. 62; Exh. HO-4, pp. II-13, II-17). The Company stated that it has requested permits and approvals for the facilities from various state and local agencies, and has received several required permits and approvals (Tr. III, pp. 67-68; Exh. BOS-15; BECO Brief, pp. 26-29). The Company's planned in-service date for the first Mystic-Downtown line is June 1989 (Exh. HO-4, p. II-13).

Mr. Gurkin testified that in the interim, certain parts of downtown Boston might have to be blacked out during summer peakload periods in 1987 and 1988 if certain "double contingency" conditions occur (Tr. III, pp. 66-69, 90-102, 107-108). Boston Edison's evidence indicates that in order to avoid overloading its lines, the Company would have to shed load during the summer of 1987 at any time the Company's system load reaches 2080 MW (i.e., 79 percent of projected

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34/At the start of this study in 1983, BECO projected its 1990 system peak demand would be above 2450 MW -- the level at which the Company estimated load shedding would have to occur if the 115 kV transmission system were not reinforced. The May 1984 report indicates that while the study was being prepared, the Company revised its demand projections and estimated the 2450 MW level would be reached by 1987/88 (Exh. BOS-14, p. 6).

peak, a load level that BECO expects to occur on 40 of the 120 summer days) and both units of the New Boston generating station are out (which BECO expects to occur on two of the 120 summer days, based on historical averages) (Exhs. BOS-10, BOS-11, BOS-12, BOS-16). For the summer of 1988, Boston Edison's evidence shows that the load-shedding threshold would be 2000 MW (i.e., 75 percent of projected peak, a load level the Company expects to occur on 60 out of the 120 summer days) (Exh. BOS-11).

The Company also states that during the 1987 and 1988 summers, if the Company's existing Mystic-K Street 115 kV transmission line goes out of service at the same time both New Boston units are out, the load shedding threshold would be lower and could be expected to be reached on more than ninety percent of the summer days in 1987 and 1988 (Id.). In this "worst case scenario" (as characterized by the Company), up to twenty-five percent of Boston Edison's customers could be blacked out (Tr. III, pp. 98-100; DPU 86-255, Exh. BE-36, p. 6; BECO Brief, p. 29).[35]

Mr. Gurkin testified that if any of these double-contingency or worst-case conditions occur in the summer of 1987 or 1988, Boston Edison will have to black out certain parts of the Boston area by sequentially disconnecting specific circuits on certain substations on its downtown transmission system until the Company's load is adequately reduced to avoid overloading the line(s) (Tr. III, pp. 70-76; Exhs. BOS-9, BOS-10). According to Mr. Gurkin, BECO customers in South Boston, Roxbury, Jamaica Plain, the South End, and Dorchester are served by the substations identified for disconnection if contingencies occur (Tr. III, p. 73). Mr. Gurkin testified that these areas have been selected for engineering reasons, since these areas

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35/BECO estimates worst-case planning scenarios based on a "base-case" condition which assumes a certain amount of generation already out of service and then looks at the effect on the transmission system of the next two contingencies (Tr. III, pp. 118-119; DPU 86-255, Exh. BE-36, p. 6). BECO asserts that the probability of losing an underground transmission line is three orders of magnitude less than the probability of a generating unit going out of service unexpectedly (Exh. BOS-11).

are served by radial lines, which are easier to disconnect than lines on networks (such as those serving downtown Boston) (Tr. III, pp. 75-76).

Mr. Gurkin also testified regarding several interim measures the Company has taken to improve the reliability of the existing Boston transmission system before the Mystic-Downtown line is completed (Tr. III, pp. 108-112). The Company shows that, based on internal recommendations made in late 1983 and spring 1984, the Company has installed a forced cooling system and a heat-sensing cable monitoring system on parts of the downtown transmission system (Tr. III, pp. 108-109, 112, 121-122; Exh. BOS-17). The Company asserted that it "recognized that required reinforcements could not be built before 1989 and it moved quickly to implement these interim actions in order to minimize potential adverse reliability impacts on customers in the downtown area" (BECO Brief, pp. 33-34).

In conclusion, the Company argues that it "has adequately planned to meet the energy supply requirement of its customers in the City of Boston" (Id., p. 25). Furthermore, the Company asserts that a Siting Council review of the Company's supply plan is not the proper forum for investigating the "Downtown Problem" since the instant proceeding does not involve a request for approval of facilities (Id., pp. 25-34).

### 2. The City of Boston's Position

The City of Boston asserts that Boston Edison "cannot provide a necessary energy supply to the City of Boston" since "the Boston Edison Company, through its own fault, has placed the City of Boston in severe jeopardy of blackouts in 1987 and 1988" (City Brief, p. 1).

The City avers that the Company has known for at least four years that the City of Boston is likely to have a blackout two or three times during the summer of 1987 and more often during the following summer (Id., pp. 1, 8-12). While the City acknowledges the Company's plan to add a forced cooling system and construct the Mystic-Kingston line, the City argues that these "solutions are both too little and too late" to resolve the impending problems in 1987 and

1988 (Id., pp. 3-4).

Citing the Company's evidence on the likelihood of a simultaneous outage of both units at New Boston and the likelihood that load levels would reach the load-shedding threshold if that contingency occured, the City asserts that the probability that customers in South Boston, Roxbury, Dorchester, and Jamaica Plain will be disconnected is 33 percent in the summer of 1987 and 50 percent in the summer of 1988 (Id., pp. 4, 12-15).

Finally, the City asserts that this situation "epitomizes BECO's abandonment of its public interest function" (Id., p. 4) and is endangering the public health, safety and welfare of the City for at least the next two years (Id., pp. 15, 23).

In regard to the Company's plans to resolve these problems by mid-1989 through the construction of new facilities, the City alleges that the Company has failed to seek approvals from all of the City's bodies that have statutory authority to grant permits required for the construction of the proposed Mystic-Downtown line (Id., pp. 7-8). Further, the City asserts that the Company has not complied with the 1977 condition imposed by the Siting Council in its approval of the Mystic-Downtown line that the Company enter into negotiations with state or local governments as to matter of final design, engineering and construction of the line (Id., p. 7). The City therefore questions whether "through untimely application by BECO,...BECO's 1989 solution may be delayed which, in turn, exposes the City to further risk of blackouts" (Id., p. 7).

The City urges the Siting Council to reject Boston Edison's filing as "incomplete, untimely and lacking in a specific remedial plan for action" (Id., p. 23).

The City also requests that the Siting Council direct BECO to: seek all outstanding approvals for the Mystic-Kingston line; submit to the Siting Council and the City detailed reports on a monthly basis concerning the Company's progress in obtaining all necessary approvals for all construction already identified as necessary to alleviate the downtown problems; and provide the Siting Council and the City with contingency plans specifically designed to alleviate the blackout conditions BECO concedes are likely to occur (Id., pp. 23-24).

Finally, the City asserts that since the statutory authority to require a company to fulfill its public interest obligations rests with the MDPU rather than the Siting Council, the Siting Council should ask the MDPU to investigate how BECO management allowed the summer 1987 and summer 1988 downtown Boston reliability problems to develop (Id., pp. 4-5, 23-24).

### 3. Evaluation of the Company's Transmission System Planning

#### a. Jurisdiction

The Company has argued that a review of the adequacy of its transmission system is not appropriate in this proceeding. BECO asserts that the sole issue before the Siting Council is the adequacy of the Company's demand forecast and supply plan (BECO Brief, pp. 25-26).

The Siting Council rejects the Company's assertion that this proceeding is an improper forum for addressing issues relating to the adequacy of the Company's transmission system planning and plans. In considering these transmission issues in the current review of the Company's long-range supply plan, the Siting Council is clearly fulfilling its statutory mandate.

First, the Siting Council's statute explicitly ties companies' ability to commence construction of facilities to Siting Council determinations as to whether those facilities are consistent with the most recently approved long-range forecast or supplement thereto. G.L. c. 164, sec. 69I.

Secondly, G.L. c. 164, sec. 69I requires companies to file descriptions of actions they plan to take which will affect their ability to meet their customers' electric power needs and requirements. These descriptions are required to include plans for constructing facilities and for reducing requirements through load management. In accordance with this statutory scheme, the Company presented the Mystic-Golden Hills transmission line proposal as part of its 1985 long range forecast (Exh. HO-2, Sec. II). Although the

facilities proposal was ultimately severed from the complete filing in order to expedite its review, Boston Edison Company, 13 DOMSC 63 (1985), the Company in its initial filing clearly recognized and understood that facility proposals are typically considered as part of an overall long-range forecast review.

Third, the Siting Council consistently reviews the adequacy of transmission-related issues even in proceedings where the company has proposed no jurisdictional facilities. In Masschusetts Electric Company, et al., 15 DOMSC __ (1986) [EFSC Docket 83-24], the Siting Council considered an electric company's compliance with conditions attached to a previous approval of a facility within the context of reviewing a long-range forecast.

Accordingly, the Siting Council finds that consideration of the Company's transmission plans and planning is critical to a meaningful review of the Company's supply plan and, as such, falls squarely within the Siting Council's jurisdiction.

### b. Adequacy of the Downtown Transmission System

To analyze the adequacy of its downtown Boston transmission system, the Company used load-flow studies to analyze the adequacy of its transmission system under certain assumed load, generation and transmission conditions (Tr. III, p. 15). The Company analyzed the performance of the downtown system in the event of double contingencies and also under worst case scenarios (Tr. III, p. 66). Based on the results of such analyses, the Company identified the need to shed load at substations serving parts of the City of Boston in the event of New Boston units 1 and 2 were to go out of service during load conditions at 79 percent of peak in summer 1987, and at 75 percent of peak in summer 1988. The Company asserted that the likelihood of load shedding in parts of the City of Boston was unacceptably high until BECO could resolve the problem through the installation of a new 345 kV transmission system in downtown Boston.

Consistent with findings made in previous decisions, the Siting Council finds that: (a) the Company's use of load flow studies is an acceptable method for analyzing the performance of a transmission

system under different assumed conditions; (b) Boston Edison's use of double-contingency assumptions is an appropriate method for analyzing the reliability of its downtown transmission system; and (c) the Company's need to shed load in the event of reasonable contigencies is a problem that an electric company should plan to avoid. In re Cambridge Electric Light Company, 15 DOMSC __, 17, 20, 23 (1986); In re Massachusetts Electric Company, et al., 13 DOMSC 119, 194, 198 (1985); and In re Boston Edison Company, 13 DOMSC 63, 70-73 (1985).

Based on the record in this proceeding, the Siting Council finds that Boston Edison has known since 1983 that by the late 1980s the Company faced an unacceptably high risk of having to disconnect customers in the event of the double contingency that both units of New Boston go out of service during peak load periods (Tr. III, p. 102; Exh. BOS-14).

The Siting Council finds further that in 1983 and 1984 the Company proposed certain plans to upgrade and reinforce its existing downtown transmission system. These plans included (a) adding a forced cooling system and a heat-sensing cable monitoring system on portions of the existing 115 kV transmission system, and (b) construction of a new 345 kV downtown transmission system, the first phase of which was planned for 1988 (Exhs. BOS-17, HO-2, sec. II). The improvements to the 115 kV system have been installed and are operating. The first portion of the planned 345 kV downtown transmission system is not yet under construction and is now expected by the Company to be in service by June 1989.

The Siting Council finds that the Company's completed reinforcements to the its 115 kV downtown transmission system have contributed to the improvement of the reliability of that system. But in light of the fact that the Company itself views these efforts as "interim actions in order to minimize potential adverse reliability impacts on customers in the downtown area" (City Brief, pp. 33-34, emphasis added), the Siting Council finds that until the Company can put the planned 345 kV Mystic-Downtown transmission line in service, the Company's upgraded 115 kV transmission system is inadequate to avoid the risk of disconnecting customers in parts of Boston in the event that both units of New Boston go down during summer peakload

conditions.

With respect to the level of risk that exists regarding load shedding in parts of the City of Boston during the summers of 1987 and 1988, the City asserts that based on the Company's evidence,[36] the risk of a blackout is 33 percent in the summer of 1987 and 50 percent in the summer of 1988 (City Brief, pp. 4, 12-15). The Company asserts it did not calculate the probability that load would have to be shed in 1987 and in 1988 (Tr. III, pp. 101-102). However, based on testimony and exhibits presented by BECO, the Siting Council finds that the risk of a blackout in parts of the City of Boston as 56 percent in the summer of 1987, and 75 percent in the summer of 1988.[37] In light of this evidence, the Siting Council finds that the risk of a blackout in the City of Boston is intolerably high during the summers of 1987 and 1988 -- and in all subsequent summers if the Company has not put the new Mystic-Downtown line into service.

For that reason alone, the Siting Council finds that Boston

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36/The Company's evidence is not provided in the form of joint probabilities (Tr. III, p. 98). The Company's explanation of load-shedding risk is expressed quantitatively as follows: "Assuming all downtown transmission lines in service[,] load curtailment could be required for Boston Edison load levels in excess of approximately 2080 MW, 79% of peak in 1987. This load level would typically be reached or exceeded 40 days during the 1987 summer. For the 1988 summer the load disconnection threshold level will decrease to approximately 2000 MW, 75% of peak. This load level should be achieved approximately 60 days. Load shedding would be triggered only if both New Boston units were out-of-service on these heavy load days. Based on experience the simultaneous unavailability of both New Boston units could be expected to occur one to two days each summer" (Exh. BOS-11; see also Tr. III, pp. 93-98). The Company states that the load-related and generation-related contingencies are independent in terms of their probability of occurence (Tr. III, p. 97).

37/The Siting Council's risk calculation is attached in Table 7. This calculation assumes the data presented in the footnote above, which relates to a double contingency case (i.e., all existing transmission lines operating and two generating units going out), rather than a "worst case" contingency (which assumes the additional loss of a Mystic-K Street 115 kV line) (Exh. BOS-11, Tr. III, pp. 118-120).

Edison is not ensuring an adequate supply of reliable power to its customers in the City of Boston.

### c. The Company's Transmission System Planning Process

The Siting Council also addresses the question of whether the Company has proceeded with its transmission planning in a manner that has attempted to provide for an adequate supply of reliable power for all of its customers; and in particular for customers in the City of Boston.

Starting in 1983, the Company recognized that it would not be able to install new, planned 345 kV transmission facilities in downtown Boston by the time they would be needed to avoid load shedding under certain reasonably likely contingencies. The Company undertook facility-related actions starting in 1983 and 1984, so as to lower the risk of a blackout in the City of Boston -- a risk that would exist until the new 345 kV transmission facilities were in place. The Company has proceeded with the licensing of its proposed first 345 kV Mystic-Downtown line, and the Company expects to put it in service by summer 1989.

While the Siting Council rejects the City's allegation that the Company has been idle on the Downtown Problem (City Brief, pp. 7-8), the Siting Council notes that the Company has failed to address its transmission problems with due diligence. For example, while the Company filed an Environmental Notification Form with the state in March 1985 and received from the Executive Office of Environmental Affairs an approval of the Company's Final Environmental Impact Report on February 26, 1986, the Company did not petition the MDPU for a Certificate of Convenience and Necessity until November 1986 (BECO Brief, p. 27). This sort of delay does not support a finding that Boston Edison has initiated a licensing schedule for the Mystic-Downtown line that adequately responds to the urgent need for the line.

Further, the Siting Council finds that the Company did not explore all possible options for minimizing the risk of a blackout in

downtown Boston in the short run. In 1983, when the Company began to realize that it would not be able to place its proposed Mystic-Downtown line into operation soon enough to avoid the risk of load shedding during summer peakload conditions and under certain generation contingencies, the Company evaluated only "do nothing" and transmission-facility solutions to the problem. Ultimately, the Company identified and implemented certain "interim measures" to upgrade its existing transmission system until BECO could put its preferred transmission-system reinforcement plan into place in 1989.

However, the Company provided no testimony or exhibits to show that since 1983 the Company ever considered any solutions that would have enabled the Company to influence the type or pace of load growth in downtown Boston that was hastening the need for the new 345 kV transmission line. The record reveals no efforts on the part of Boston Edison between 1983 and 1986 to reduce the pace of growth through encouraging more energy-efficient building construction practices or the installation of efficient electrical equipment or appliances in new commercial buildings in downtown Boston.

Further, the Company stated that it does not change the schedule or design of its conservation and load management strategies as a response to faster-than-expected load growth (See Section III.G, infra). If the Company had started in 1983 to implement an aggressive load-management strategy targetted at downtown Boston customers and aimed at enabling the Company to better manage downtown Boston loads during summer peakload conditions, the magnitude of the Company's potential load-shedding problem during the upcoming two summers might have been reduced.

The Company decided only late last year to implement a few load-management programs in 1986 and 1987 under which the Company would pay customers to shed or shift their loads off of the Company's peak.[38] But the Company has not targetted these programs at

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38/ In August, 1986, and December, 1986, the Company's management authorized several conservation and load management programs for implementation starting in late 1986 and 1987 (Exh. HO-159). Two of these programs -- the "Generator Assistance on Peak" program and the "G-3 Load Curtailment" (footnote continued)

downtown Boston customers (Exh. HO-159; Tr. I, pp. 24-25). In addition to waiting too long to decide to implement these programs, the Company's current implementation schedule for them is too slow for the Company to use these load-management options to help minimize the Downtown Boston reliability problem during 1987 and 1988 (Id.).

Still, the Siting Council sees no reason why the Company could not start today to implement even these programs much more aggressively as a way to help the Company reduce the risk of a blackout in parts of the City of Boston during the next two summers.

Absent evidence that the Company ever considered any such load-management options as even partial solutions to the Downtown Problem in the short run, the Siting Council finds that the Company has not adequately planned for providing reliable service to the City of Boston.[39] Further, the Siting Council finds that Boston Edison's

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(footnote continued) program -- are designed to enable the Company to pay customers so that BECO can call upon them to shed load during the Company's peak period (Id.). During the 1987 summer season, Boston Edison plans to have only five customers involved on the Generator Assistance on Peak program, and ten customers on the G-3 Load Curtailment program (Id.). The other seven programs include: a thermal storage load-shifting program for commercial/industrial customers; a flourescent light rebate program for commercial/industrial customers; a similar program for residential customers; a central air conditioner load-management program for residential customers; a similar one for commercial/industrial (G-2) customers; a program to offer rebates to residential customers to purchase energy-efficient refrigerators (Id.)

39/As further evidence of the Company's planning inadequacies relating to the Downtown Problem, the record shows that if the Company had pursued its plan to convert New Boston 1 and 2 to coal -- a plan BECO abandoned some time in late 1985 or early 1986 -- the Company would have taken each of these units out of service for an extended period of time at different points during the summers of 1987 or 1988 (Tr. II, pp. 186-191). If BECO had actually gone through with the coal conversion at New Boston, the Company would have placed customers in the City of Boston at a heightened risk of a blackout during each conversion-related outages, since (a) the Mystic-Downtown line would not yet be in operation, (b) there would be a 100-percent likelihood that one of the New Boston units would be out, and (c) load in parts of the City of Boston would have to be shed if the other one went out (i.e., a single contingency, rather than a double contingency). BECO actively pursued this plan for at least a year beyond the time the Company realized it could not put its proposed Mystic-Downtown transmission line in service before 1988 or 1989.

inadequate planning has exposed firm customers in parts of the City of Boston to an unacceptably high risk of a blackout in the summers of 1987 and 1988.

The record demonstrates that the Company has not integrated its transmission system planning with its resource planning process in general and in particular with respect to its demand-management planning (see section III.G for a further discussion of this issue).

Based on the foregoing, the Siting Council finds that Boston Edison has failed to adequately plan to ensure a reliable power supply for its customers.

G. Least-Cost Supply

The Company states that its planning process is designed to ensure that Boston Edison has an optimal supply and demand plan (Exh. HO-10, p. 2). BECO asserts that it achieves a least-cost resource plan through application of a uniform standard for comparing alternatives: "the standard against which supply and demand plans are measured is marginal capacity costs and marginal fuel costs. Mixes of various supply and demand options (including rate design and strategic marketing) are examined with the object of selecting a combination which results in the lowest future cost-of-service for our customers" (Id.).

The Company states that this process "ensures that the Company will build generation facilities only when they are the most economic resource when compared to other options (supply and demand) on a standard basis" (Id., p. 19).

With respect to conventional power supplies, the Company says it uses its EGEAS and internal production-costing techniques to identify and develop an expansion plan that minimizes cost (Exh. HO-9, p. 5; Exh. HO-10, pp. 17-19). (See also Section III.C, supra.)

In terms of how the Company treats power purchases from small power producers and cogenerators within its least-cost resource planning, BECO has provided evidence about its new contracting procedures for purchasing electricity from such facilities within the context of a least-cost resource planning process (Exhs. HO-12, HO-13). (See Section III.C, supra.)

Regarding inclusion of demand management in the Company's least-cost plan, Boston Edison states that it utilizes a process that leads the Company to implement conservation and load-management "measures which affect the use of electricity in such a way as to keep the cost of power lower, for all customers, than it would have been if the action was not taken" (Exh. HO-10, p. 21). (See Section III.C, supra.) The Company argues that "it has made significant progress over the past few years, particularly since the end of 1984, in the development of a sound basis and approach to demand management planning. The principal accomplishments include not only the three

programs that are now running on a full-scale basis, but also the process whereby those programs are conceived, evaluated and moved towards full scale implementation" (BECO Brief, p. 19). The Company asserts that this process yields "a workable solution for placing demand-side options on an equal footing with supply-side options" (Exh. HO-7, p. 13).

The City argues that the Company has not addressed the issue of least-cost planning as required by the Siting Council (City Brief, p. 25). However, the City provided neither its own evidence nor a detailed analysis of the Company's evidence as support for the City's position.

The Company's commitment to demand-management programs as part of a least-cost planning strategy has been criticized in another forum. On June 26, 1986, the MDPU issued an order which concluded that the Company had failed to meet its public service obligation. Boston Edison Company, DPU 85-266-A/85-271-A (1986).[39a] In that case, the MDPU concluded that "the Company has not engaged in a least-cost planning strategy because it has adopted planning criteria which prevent the implementation of cost-effective energy conservation and load-management...programs. Such programs could have been designed to delay, in a cost-effective manner, the date additional capacity will be needed. We find in this Order that this failure has resulted in a cost of service higher than would exist had the Company made a true commitment to reasonable C&LM measures" (Id., p. 10; See also pp. 6-15).

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39a/ In this proceeding, the Siting Council has taken administrative notice of the following dockets of the Massachusetts Department of Public Utilities: DPU 85-266-A/85-271-A, DPU 1720, and DPU 85-58 (Tr. I, p. 4); DPU 1350 (Tr. II, p. 137); DPU 86-78 (Tr. III, p. 49); and DPU 86-255 (Tr. III, p. 68).

### 1. Comparison of Alternatives on an Equal Footing

Boston Edison provided extensive evidence in the form of testimony and documentation as to how the Company evaluates resource alternatives when it attempts to develop a least-cost, reliable supply plan (Exhs. HO-3, HO-5, HO-6, HO-7, HO-8, HO-9, HO-10; Tr. I, pp. 22, 53, 69-79; Tr. II, pp. 26-30). To facilitate the development of such a plan, the Company said it reorganized its supply and demand planning functions into a single department that includes: demand forecasting; planning for and evaluation of conservation and load management; planning and contracting for SPP and cogeneration; and more traditional generation expansion planning (Exh. HO-10; Tr. I, pp. 68-69, 73-78; Tr. II, pp. 98-100; BECO Brief, p. 14). Mr. Hahn testified that in the past three years, BECO's demand-management planning has been bolstered with resources and that Boston Edison now has a "truly integrated supply and demand planning process...that takes a back seat to no one" (Tr. I, p. 69).

The Siting Council recognizes that Boston Edison has effected a number of changes since the last time the Siting Council issued an order on a BECO filing. In particular, the Siting Council acknowledges the harsh criticism the Company received regarding its planning process as a result of the June 1986 MDPU order. Accordingly, throughout this entire proceeding, the Siting Council repeatedly and explicitly requested the Company to provide information that could reflect not only the evolutionary nature of the Company's planning process, but also the ways in which the Company has responded to that order.

The record in this proceeding is replete with evidence which shows that the Company utilizes different analyses and decision-making standards for demand-management resources than it employs for supply-side resources. This differential treatment undermines the Company's ability to develop a least-cost plan in a number of ways:

(1) Mr. Hahn stated that he has never examined and therefore is unaware of whether it would be cheaper (e.g., in terms of system revenue requirements) for the Company to meet the marginal kilowatt or kilowatthour of demand through a supply-side approach or through a

demand-side approach (Tr. II, pp. 45-53). For example, the Company never considered implementing demand-management programs on a more aggressive schedule as a source of (a) replacement power for the energy lost due to the lengthy, on-going outage of Pilgrim 1[40] (Tr. I, p. 141; Tr. II, pp. 164, 173, 192), or (b) to avoid capacity deficiencies in the short run if the Company's planned additions are not available as expected (Tr. II, p. 166). Similarly, even when it changes its load-growth or fuel-price assumptions in its contingency plans, the Company never varies its expectations with regard to what demand-management programs would then be cost-effective and whether it should modify its demand-management implementation schedule or the economic incentives embodied in any individual program (Exh. HO-9; Tr. II, pp. 30, 33-37, 39-40, 42-45).[41]

In the event of these contingencies, the Company relies upon only conventional power purchases or investments in traditional powerplant projects as viable responses. In fact, the Company even calls its long-range supply plan and its action plan an "expansion plan" (BECO Brief, p. 20). Further, Mr. Hahn stated that BECO had not compared the costs of the nine demand-management programs now authorized for implementation against the ceiling price established for buying power from SPP and cogenerators in the auction process (Tr. I, pp. 45-46). The Company concedes that it may have missed some opportunities for obtaining cost-effective power supplies when it did not evaluate whether demand management would be cheaper to implement than the kinds of supply-side options it has pursued in the short run

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40/BECO asserts that "Until Pilgrim returns to service, the Company will continue to seek the least cost replacement energy available" (BECO Brief, p. 24; see also Tr. I, p. 141). However, under cross-examination, Mr. Hahn stated that the Company never considered changing its demand management schedule as a source of replacement energy for Pilgrim (Tr. II, pp. 191-192).

41/Once the Company selects as a candidate for implementation a program from the original list of 40 options, the Company evaluates the sensitivity of that program's benefit/cost ratio to varying assumptions regarding participation rates, discount rates, and so forth (Tr. II, pp. 41-44).

(Tr. I, pp. 56-57).

As such, the Siting Council concludes that the Company's supply planning process can only view these supply-side and demand-side options in a non-integrated way.

(2) The Company's witness, Mr. Ruscitto, explained that in BECO's evaluations of 40 demand-management options, a benefit/cost ratio greater than one for any particular program indicates that the Company could implement that program and provide a lower cost of supply relative to a resource mix that did not include that program (Tr. I, pp. 17-18). When the Company performed its analyses of the 40 demand-side programs, 36 of them had a benefit/cost ratio greater than or equal to one. However, in spite of the Company's own expectation that it will need to add capacity both in the short run and the long run (see Section III.E, supra), and even though the Company has recognized since 1983 that a downtown Boston reliability problem would arise before the Company could build a transmission facility to correct it (See Section III.F, supra), the Company has chosen to implement only a small set of the 36 demand-management programs for which its own analyses show favorable benefit/cost ratios and whose implementation would provide the opportunity to lower customers' costs relative to a supply mix that excludes those programs (Tr. I, pp. 53-54; Tr. II, p. 200).

This is particularly troubling in light of statements by Mr. Hahn and Mr. Ruscitto that the Company has significantly modified its approach to demand management in response to being placed on notice by the MDPU in its June 1986 Order that there was an immediate need for the Company to pursue demand management as part of a least-cost supply plan (Tr. I, pp. 21-22, 70-72). In August 1986 -- two months after the MDPU issued its decision -- the Company authorized and commenced implementation of only three programs, and in December 1986, the Company approved only six more for implementation (Exh. HO-159). According to Mr. Hahn, such authorizations represent the "corporate commitment" to a particular demand-managment program (Tr. II, p. 104). Mr. Hahn and Mr. Ruscitto stated that the MDPU's order had a major impact on the Company and that Boston Edison is responding as quickly as possible at this point (Tr. I, p. 31-32, 52-53; Tr. II, p. 25).

However, the Siting Council concludes that if the Company were actually making substantial changes in order to pursue a reliable and least-cost supply mix, it would be aggressively implementing all cost-effective demand management throughout the Company's service territory and targetting the marketing of such efforts in areas such as parts of the City of Boston where the Company has identified as potential locations for reliability problems in the short run.

The record shows that Boston Edison is doing neither of those things. Accordingly, the Siting Council finds the Company is not aggressively pursuing all cost-effective demand management in spite of the Company's expectation that it needs to add energy supplies and capacity.

(3) The Company has developed a detailed and comprehensive computerized methodology for comparing the costs and benefits of demand-management programs (Exh. HO-8; Tr. II, pp. 126-130, 155-157). This approach provides the Company with a relatively sophisticated and sound methodological foundation for performing the kinds of analyses the Company needs to develop least-cost plans. However, the Company does not apply this metholodogy in a way that enables the Company to carry out least-cost planning over time (Tr. II, p. 35). The record shows that the Company has used its methodology to evaluate the Company's 40 conservation and load-management options only once in the past three years, and to evaluate the Company's proposed pilot programs only one other time since then (Tr. I, pp. 35-44; Tr. II, pp. 33-37; Exh. HO-153).

This is the case in spite of the fact that the Company recognizes that many of the factors that signficantly affect the Company's forecasted need for new capacity and its long-run marginal energy and capacity costs have changed significantly during that time and could change again within the short run (Tr. I, pp. 39-42, 119-121; Tr. II, pp. 27-28, 40-41). Mr. Hahn stated that BECO plans to rerun the analyses on the full set of options only as early as summer 1987 (Tr. I, pp. 42-43). At the same time, the Company reestimates its contingency analyses of more traditional power purchase options on a more regular basis (Tr. I, pp. 102-103; Exh. HO-69).

The Siting Council finds that the Company has failed to use this methodology iteratively and often to analyze whether demand-management programs remain cost-effective even under different assumptions (e.g., what level of a lighting rebate would still be cost-effective if the Company's marginal cost went up). Therefore, the Siting Council finds that the Company has failed to adequately monitor changes in the cost effectiveness of its demand-management options in accordance with changes in the Company's avoided cost estimates.

(4) Boston Edison has no common basis for directly comparing the economic benefits and costs associated with demand-side options against those of supply-side options. To compare demand-management programs against each other, the Company calculates their net present value and benefit/cost ratios, using the Company's long-run marginal cost as the basis for valuing benefits (Tr. I, p. 49). To compare SPP and cogeneration options against alternative supply-side options, the Company establishes a long-run cost of avoided energy and capacity in terms of a levelized cents-per-kilowatthour cost ("¢/kwh") and then allows SPP and cogenerators to submit bids to sell electricity to the Company at or below that cost. Mr. Hahn testified that: (a) Boston Edison does not have a ¢/kwh cost value for any of the 40 demand-management options it had analyzed; and (b) it would take weeks to calculate such values using up-to-date assumptions (Tr. I, pp. 46-50; Tr. II, pp. 50-51). Mr. Hahn admits that he has not made such direct cost comparisons of demand-management options and supply-side options (Tr. II, pp. 45-53).

Therefore, the Siting Council concludes that the Company's analytic measures do not accommodate economic comparisons of demand-side options directly against supply-side options.

(5) In response to questioning from the Siting Council, Mr. Hahn expressed his concerns about articulating the risks associated with particular contracts the Company holds with independent power producers for as-yet unconstructed projects, since he did not want to give the impression that the Company was undermining the ability of those projects to come on line (Tr. I, pp. 104-105). Yet, Mr. Hahn and Mr. Ruscitto repeatedly articulated the Company's concerns about

the "questionable" feasibility of demand-side management programs due to customers' disinterest or unwillingness to participate in the Company's demand-management programs (Tr. I, pp. 30, 53, 101, 104-105, 118-119; Tr. II, pp. 31-33, 43, 57).

The Siting Council finds that the Company adopts a different attitude regarding articulating the risks of demand-management options than it has about discussing the risks of specific supply projects.

(6) In the Company's supply planning process which includes a base case, contingency analyses and expansion plans, the Company analyzes the economics of supply-side additions using 100-MW capacity increments (Exh. HO-9, p. 7). Boston Edison argues that the reason the Company cannot include demand-management options within its contigency planning framework is that demand-management options come in much smaller increments and offer limited "supplies" in absolute terms (i.e., less than 100 MW at a time) (Exhs. HO-25, HO-28).

Based on this assertion alone, the Siting Council finds that the Company has failed to establish that its expansion planning methodology is unbiased with respect to its treatment of demand-side versus supply-side options that the Company can call upon in response to contingencies.

(7) The 1986 Boston Edison Forecast included adjustments for conservation, load management and time-of-use rates associated with the long-run effects of implementing all cost-effective programs starting with the six pilots proposed in 1985 (Exh. HO-3; Exh. HO-7). (See Table 8.) Since that filing was presented to the Siting Council, the Company realigned its schedule for implementing demand-management programs, but according to Mr. Ruscitto, those changes would not alter the conservation/load management adjustments the Company made to the 1986 Forecast (Tr. I, pp. 32-35). The Company did not provide documentation in support of this assertion.

Accordingly, the Siting Council finds that the Company's estimates of demand-management resources the Company can rely upon in the short run do not have a credible technical basis.[42]

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42/This finding could seem inconsistent with the Siting Council's unconditional approval of the Company's (footnote continued)

(8) Mr. Hahn and Mr. Ruscitto concede that demand-management programs could reduce forecasting error, for example, by reducing the weather-sensitivity of the energy usage of certain equipment. The Company also concedes that certain types of demand management can facilitate supply planning by reducing risk associated with demand uncertainty (Tr. I, pp. 54-56; Tr. II, pp. 55-58). However, the Company does not take this benefit into consideration when it evaluates the benefits and costs of various possible implementation schedules and strategies. The Company's witness agreed that BECO may have missed all kinds of opportunities to have captured benefits from demand management (Tr. I, pp. 56-58).

This analytic treatment of demand management by the Company means that the Company's analyses underestimate the benefits to the system of relying upon demand-side options as integral parts of the Company's supply plan. Based on the Company's testimony, the Siting Council finds that the Company has failed to consider the risks and benefits of demand management fairly in its overall supply planning process.

To the Siting Council, the Company's supply and demand planning effort reads well on paper; but, for the reasons stated above, Boston Edison is not performing analyses and actually making decisions in line with tht plan so as to enable it to develop a least-cost supply plan and minimize its customers costs of service.

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(footnote continued) 1985 and 1986 demand forecasts (See Section II.C, supra), which include the Company's adjustments for the impacts of Company-sponsored conservation, load management, and time-of-use rates, as required by the Siting Council in its previous order (See Section II.C.1.b). That unconditional approval recognized that the Company had complied with the Siting Council's explicit order to integrate demand management into BECO's forecast.

The criticism noted above relates to the Company's treatment of demand-management impacts in an inflexible way. In the future, the Siting Council expects the Company to treat demand-management plans in a way that reflects the Company's expectations about the timing and availablility of specific amounts of "supplies" that can result from implementing specific demand-management programs or strategies.

On the one hand, it is clear that the Company can perform least-cost generation-expansion planning. Further, the Company has embarked on a program to contract for power from SPPs and cogenerators within a least-cost generation-expansion planning process. But on the other hand, in spite of numerous Company statements to the contrary, the evidence overwhelmingly demonstrates that in important analytical and decisionmaking ways, the Company is still not treating demand-management resource options on an equal footing with supply-side options.

This conclusion is troublesome enough in light of the Siting Council's own statute and decisions that require companies to adequately consider conservation and load-management. G.L. c. 164, sec. 69J. In Re Cambridge Electric Light Company, et al., 15 DOMSC __ 7, 27, 40 (1986); Massachusetts Electric Company, et al., 13 DOMSC 119, 177-179 (1985). But it is all the more problematic in light of the order of the Siting Council's sister agency, the MDPU, now over nine months ago, that the Company fully integrate conservation and load management into its demand and supply planning process. MDPU 85-266-A/85-271-A, pp. 6-15, 143-151.

2. Conclusions

Accordingly, the findings above show that Boston Edison treats demand-side options differently from supply-side options in the following ways:

(1) Boston Edison's demand and supply planning process is not fully integrated;
(2) Boston Edison is not pursuing all cost-effective demand management in spite of the Company's need for energy and additional capacity;
(3) Boston Edison does not adequately monitor how the cost effectiveness of demand-management options changes over time in accordance with changes in the Company's avoided cost estimates;

(4) Boston Edison's analytic measures do not accommodate direct economic comparisons of demand-side options against supply-side options;

(5) Boston Edison has a different attitude about articulating the risks of demand management programs as opposed to discussing the risks of particular supply projects;

(6) Boston Edison's expansion planning methodology is not unbiased with respect to treating demand management and supply-side options as alternatives the Company could rely upon in response to contingencies;

(7) Boston Edison's estimates of demand-side resources available to the Company in the short run do not have a credible technical basis; and

(8) Boston Edison's analyses underestimate demand management's benefits to the system.

These findings demonstrate that Boston Edison's resource-planning process does not ensure a least-cost energy supply for the Company's customers, since BECO does not treat demand-management options on an equal footing with supply-side options in relevant analyses and decisions.

Therefore, the Siting Council finds that the Company's supply plan does not ensure a least-cost energy supply, as required in the Siting Council's enabling statute.

H. Diversity of Supply

As part of Condition 3 of its last decision, the Siting Council required Boston Edison to provide information on its fuel diversification initiatives. In this proceeding, the Company stated that it had attempted to convert generators at New Boston and Mystic to coal but had since dropped those efforts (See Section III.B, supra).

The Company also discussed another diversification effort, the conversion of three major fossil fuel units at New Boston and Mystic to dual-fuel (oil and natural gas) capability (Exh. HO-64). The Company provided a fuel-use forecast for 1986 which, when compared to a fuel-use forecast for 1983, indicates the Company's lower dependence on oil due to the dual-fuel capability. Based on those forecasts, oil generation was expected to decrease to 37 percent[43] from the 71 percent forecast for 1983; nuclear fuel generation was expected to remain constant at about 29 percent; natural gas generation was forecast to rise from virtually no generation in 1983 to about 34 percent in 1986 (Exh. HO-4, p. I-4; see also BECO's 1983 Forecast, Vol. 2, March 1, 1983, p. I-4).

The Siting Council finds that this more even balance in oil and gas generation improves the Company's fuel diversification position.

The Company also reported other diversification initiatives. Boston Edison is purchasing nuclear power from New Brunswick and plans to purchase hydro-power from Hydro Quebec under NEPOOL's Phase II purchase agreement (Exh. HO-64). In addition, the Company's RFP for attracting generation from SPPs and cogenerators provides an incentive for non-oil/gas facilities (Exh. HO-64).

Based on the foregoing, the Siting Council finds that the Company has complied with Condition 3 as imposed in the last decision.

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43/All percentages are based on fuel consumption from BECO's own generation on a British thermal unit ("Btu") basis.

## I. Summary of the Supply Plan Analysis

The Siting Council has found that the Company's supply plan fails to: (1) ensure adequate resources to meet customer requirements (Section III.E, supra); (2) ensure a reliable power supply for all of its customers (Section III.F, supra); and (3) ensure a least-cost supply of energy over the forecast period (Section III.G, supra).

Accordingly, the Siting Council rejects the Company's 1985 and 1986 supply plans.[44]

In rejecting the Company's supply plan, the Siting Council is forced to note the disquieting similarities in the Company's foot-dragging approach to: addressing the integration of cost-effective demand-management options into its supply mix; addressing all possible steps to reduce the risk of a downtown Boston transmission problem in 1987 and 1988; and addressing the possibility that the Company could lose a capacity credit for the Pilgrim nuclear power plant in the short run. In each of these cases, Boston Edison refrained from addressing the problem until such time as the Company was convinced beyond any doubt that a problem existed.

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44/The Siting Council notes that the Company has established that it is proceding with the siting of both its Mystic-Downtown and Mystic-Golden Hills transmission lines, which have been previously approved by the Siting Council. In re Boston Edison Company, 13 DOMSC 63 (1985); In re Boston Edison Company, 2 DOMSC 58 (1977). In the instant proceeding, no evidence has been presented which would indicate that these facilities are no longer necessary. In fact, the record shows that the Mystic-Downtown line is needed sooner than the Company's anticipated in-service date. The Siting Council encourages the Company to complete these projects in an expedient manner.

The Siting Council's rejection of the Company's 1985 and 1986 supply plans should not be interpreted as a recision of the Siting Council's previous decisions regarding these lines.

Therefore, the Siting Council expressly finds that commencement of construction of the Mystic-Downtown line and the Mystic-Golden Hills lines is consistent with the Company's most recently approved long-range forecast. However, the Company could not commence construction of any future facility proposals until the Company files a forecast and supply plan that is approved by the Siting Council.

Unfortunately, the record in this case is replete with evidence of the consequences of that approach. The Company's inadequate planning process has placed Boston Edison's customers at an unacceptable level of risk of having inadequate resources in the short run. At the same time, customers may face higher-than-necessary energy costs because the Company has not been conducting its planning in a least-cost fashion. The Siting Council finds this "head in the sand" approach to be woefully shortsighted and a wholesale betrayal of the Company's public service obligation.

## IV. DECISION AND ORDER

The Energy Facilities Siting Council hereby unconditionally approves the demand forecast and rejects the supply plan as presented in the Third and Fourth Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements of Boston Edison Company including the requirements of the Concord Municipal Light Plant and the Electric Division of the Wellesley Board of Public Works.

The Siting Council hereby orders Boston Edison:

(1) to develop immediately a clear and specific plan for squarely facing the possibility of losing Pilgrim capacity credit. Such plan shall include a time schedule providing for specific actions by the Company if Pilgrim generation resumption meets any further delays. The Company is ordered to file such plan with the Siting Council by May 1, 1987 and to report all Company actions that either follow or modify that plan.

(2) to develop immediately a clear and specific plan for minimizing the risk and extent of disconnecting firm customer load in the City of Boston for all summers prior to the expected in-service date of the Company's proposed 345 kV Mystic-Downtown transmission line. This plan shall identify all options available to the Company to reduce the risk and extent of load shedding in the City of Boston

including consideration of an immediate and aggressive demand management strategy. Further, the plan shall provide for actions the Company will take, including a schedule for implementing those actions, to minimize the risk and extent of load shedding in each summer covered by the plan. The Company is ordered to file such plan with the Siting Council and the City of Boston by June 1, 1987 and to report all actions that either follow or modify that plan.

Boston Edison is hereby ordered to file its next long-range forecast on February 1, 1988.

Robert Shapiro

Robert Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Stephen Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Dennis J. LaCroix (Public Gas Member). Absent: Elliot J. Roseman (Public Oil Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

April 3, 1987
Date

TABLE 1

Boston Edison Company
Demand Forecast Summary

ANNUAL REQUIREMENTS:

| | Annual Energy[1] Requirements (GWh) 1986 | 1995 | Average Annual Compound Growth Rate 1986-1995 |
|---|---|---|---|
| Residential w/Heating | 716 | 975 | 3.5% |
| Residential w/o Heating | 2,285 | 2,483 | 0.9% |
| Commercial | 6,087 | 7,841 | 2.9% |
| Industrial | 1,897 | 2,424 | 2.8% |
| Street Lighting | 135 | 135 | 0.0 |
| Wellesley, Concord | 311 | 367 | 1.9% |
| Load Management | 0 | (10) | --- |
| Losses and Internal Use | 1,075 | 1,336 | 2.4% |
| Total Energy Req's | 12,508 | 15,551 | 2.5% |

PEAK REQUIREMENTS[2] (SUMMER):

| | Peak Load[1] (MW) 1986 | 1995 | Average Annual Compound Growth Rate 1986-1995 |
|---|---|---|---|
| Residential | 415 | 468 | 1.3% |
| Commercial | 1,581 | 1,894 | 2.0% |
| Industrial | 458 | 542 | 1.9% |
| Wellesley, Concord | 62 | 74 | 2.0% |
| Total Peak Load | 2,519 | 2,980 | 1.9% |

Notes: 1. Totals may not add due to rounding.
2. Losses and internal use are added to the peak load forecast within each customer group (about 9.4 percent historically). Street lighting does not make a significant contribution to peak load.

Sources: Exh. HO-3, pp. K-9, K-11, I-33; Exh. HO-127.

TABLE 2

Boston Edison Company
Base Generation Expansion Plan[1]

Base Load Forecast, Base Fuel Forecast
(MW)

| Year[2] | Coal | Combined Cycle | Combustion Turbine | Ocean State Power | Cumulative |
|---|---|---|---|---|---|
| 1986 | | | | | |
| 1987 | | | | | |
| 1988 | | | 100 | | 100 |
| 1989 | | | | | |
| 1990 | | | | 100 | 200 |
| 1991 | | | | | |
| 1992 | | 100 | 100 | | 400 |
| 1993 | | | | | |
| 1994 | | | | | |
| 1995 | | | | | |
| 1996 | | 100 | | | 500 |
| 1997 | | | | | |
| 1998 | | 100 | | | 600 |
| 1999 | | | | | |
| 2000 | | 100 | | | 700 |
| 2001 | | 100 | | | 800 |
| 2002 | | | | | |
| 2003 | | 100 | | | 900 |
| 2004 | | | | | |
| 2005 | | 100 | | | 1000 |
| 2006 | | 100 | | | 1100 |
| 2007 | | | 100 | | 1200 |
| 2008 | | | | | |
| 2009 | | | 100 | | 1300 |
| 2010 | | | | | |
| Totals | 0 | 800 | 400 | 100 | |

Notes: 1. The Company analyzes capacity addition in 100 MW increments to avoid biases due to unit size.
2. The Siting Council presents the Company's expected generation plan through 2010 for information only. We restrict our review to our ten-year planning horizon which ends in 1995.

Source: Exh. HO-9, Table 6.

TABLE 3

Boston Edison Company
Recommended Generation Expansion Plan

Base Load Forecast, Base Fuel Forecast
(MW)

| Year | Short-Term Purchase [1] | Dispatchable Purchase [2] | Ocean State Power | Cogen and SPP | Cumulative |
|---|---|---|---|---|---|
| 1986 | | | | | |
| 1987 | | | | | |
| 1988 | 100 | | | | 100 |
| 1989 | | | | | |
| 1990 | | | 100 | | 200 |
| 1991 | | | | | |
| 1992 | | 100 | | 200 | 400 |
| 1993 | | | | | |
| 1994 | | | | | |
| 1995 | | | | | |
| 1996 | | | | 100 | 500 |
| 1997 | | | | | |
| 1998 | | | | 100 | 600 |
| 1999 | | | | | |
| 2000 | | | | 100 | 700 |
| Totals | 100 | 100 | 100 | 500 | |

Notes: 1. A short-term purchase is assumed to cover the 1988 to 1990 time period.
2. A 100 MW power purchase in 1992 may be from any party selling power, including cogenerators or SPP, but it must be dispatchable.

Source: Exh. HO-9, p. 4.

TABLE 4

Boston Edison Company
Generation Expansion Plan Sensitivity Analysis

| Load Growth: | Low | Base | High | Low | Base | High | Low | Base | High |
|---|---|---|---|---|---|---|---|---|---|
| Fuel Prices: | Low | Low | Low | Base | Base | Base | High | High | High |
| Year | (1),(2),(3) | | | | | | | | |
| 1986 | | | | | | | | | |
| 1987 | | | CT | | | CT | | | CT |
| 1988 | | CT | CT | | CT | CT | | CT | CT |
| 1989 | | | CT | | | CT | | | CC |
| 1990 | | OSP | OSP | | OSP | OSP | | OSP | OSP |
| 1991 | OSP | | | OSP | | | OSP | | |
| 1992 | CT | CT,CT | CT,CT | CT | CC,CT | CC,CT | CC | CC,CC | CC,CC |
| 1993 | | | CT | | | CC | | | CC |
| 1994 | | | CC | | | CC | | | CC |
| 1995 | | | | | | | | | |
| 1996 | | CT | CC | | CC | CC | | Coal | Coal |
| 1997 | | | CC | | | CC | | | Coal |
| 1998 | | CC | | | CC | | | Coal | |
| 1999 | | | CC | | | CC | Coal | Coal | Co,Co |
| 2000 | CT | CC | CC | CC | CC | CC | | | |
| 2001 | | CC | CC | | CC | CC | | Coal | Coal |
| 2002 | | | CC | | | CC | | Coal | Coal |
| 2003 | | CC | CC | CC | CC | CC | Coal | | Coal |
| 2004 | CC | | CC | | | CC | | Coal | Coal |
| 2005 | | CC | CC | | CC | CC | | | Coal |
| 2006 | | CT | CC | CT | CC | CC | CC | CC | Coal |
| 2007 | CT | CT | CT | | CT | CC | | CC | CC |
| 2008 | | | CT,CT | | | CT,CT | | CT | CT,CT |
| 2009 | | CT | CT | | CT | CT | | | CT |
| 2010 | | | CT | | | CT | | | CT |
| Totals (MW) | 500 | 1300 | 2300 | 500 | 1300 | 2300 | 500 | 1300 | 2300 |

Notes: 1. CT = Combustine Turbine; CC = Combined Cycle; Co = Coal; OSP = Ocean State Power.
2. Each time a unit is identified, it represents an addition of 100 MW.
3. The 200 MW purchase from Pt. Lepreau II is assumed to be indefinately deferred.

Source: Exh. HO-9, Tables 6 and 9 - 16.

TABLE 5

Boston Edison Company
Consolidated Demand Forecast and Generation Expansion
Summer Peak (MW)

| Year | Summer Capability Respons | Current Summer Capacity & Purchases | Total Signed & Approved Purchases | Surplus (Deficit) | Total Likely Purchases | Surplus (Deficit) |
|---|---|---|---|---|---|---|
| 1987 | 2947 | 2984 | 250 | 287 | 0 | 287 |
| 1988 | 3328 | 2984 | 250 | (94) | 0 | (94) |
| 1989 | 3350 | 2984 | 264 | (102) | 40 | (62) |
| 1990 | 3400 | 2984 | 426 | 10 | 168 | 178 |
| 1991 | 3501 | 2884 | 426 | (191) | 343 | 152 |
| 1992 | 3408 | 2784 | 176 | (448) | 343 | (105) |
| 1993 | 3417 | 2784 | 176 | (457) | 343 | (114) |
| 1994 | 3458 | 2783 | 176 | (499) | 343 | (156) |
| 1995 | 3466 | 2783 | 176 | (507) | 343 | (164) |
| | | Capacity Losses: | Signed & Approved: | | Likely Purchases: | |
| | | Bear 1991 | NU 1987 to 1991 | | PRS 1989 | |
| | | PL I 1992 | TDEn 1989 | | BioEn 1989 | |
| | | MDC 1994 | Peat 1989 | | OSP 1990 | |
| | | | EvrtE 1990 | | AmR-F 1990 | |
| | | | NEA 1990 | | HQ 2 1991 | |

Notes: 1. Capability responsibilities are based on the Company's assumptions of 70% PIP phase in during 1987 and Seabrook I on-line in June 1987.
2. "Approved" purchases indicate MDPU contract approval; "likely" purchases have been signed by the parties but do not have MDPU approval.
3. Totals do not include expected capacity additions due to the Company's January 1987 Request for Proposals. Boston Edison has designed its RFP to attract 200 MW of cogeneration or SPP by 1991.
4. Everett Energy (EvrtE) was formerly known as Diamond East.
5. The Walpole combustion turbine is not included in the supply totals. The Walpole CT is rated at 76 MW and could be in service for the 1989 summer.

Sources: Exhs. HO-14 thru HO-84, HO-157.B, and HO-161.

TABLE 6

Boston Edison Company
Short-Run Contingency Analysis

1. Simultaneous loss of Ocean State, Northeast Energy, and Everett Energy:

| Year | Base Case[1] Surplus (Deficit) | Loss of OSP, NEA, and EvrtE | Contingency Surplus (Deficit) | NU Purchase | Walpole Combustion Turbine | Possible Surplus (Deficit) |
|---|---|---|---|---|---|---|
| 1987 | 287 | 0 | 287 | 150 | 0 | 437 |
| 1988 | (94) | 0 | (94) | 150 | 0 | 56 |
| 1989 | (62) | 0 | (62) | 150 | 76 | 164 |
| 1990 | 178 | (252) | (74) | 150 | 76 | 152 |

2. High load growth rate:

| Year | High Load Growth Forecast | Summer[2] Capability Respons | Contingency Surplus (Deficit) | NU Purchase | Walpole Combustion Turbine | Possible Surplus (Deficit) |
|---|---|---|---|---|---|---|
| 1987 | 2718 | 3094 | (140) | 150 | 0 | 10 |
| 1988 | 2832 | 3501 | (267) | 150 | 0 | (117) |
| 1989 | 2926 | 3544 | (256) | 150 | 76 | (30) |
| 1990 | 3001 | 3604 | (26) | 150 | 76 | 200 |

3. Loss of Pilgrim Capacity Credit:

| Year | Base Case[1] Surplus (Deficit) | Loss of Pilgrim Capacity | Contingency Surplus (Deficit) | NU Purchase | Walpole Combustion Turbine | Possible Surplus (Deficit) |
|---|---|---|---|---|---|---|
| 1987 | 287 | 0 | 287 | 150 | 0 | 437 |
| 1988 | (94) | (495) | (589) | 150 | 0 | (439) |
| 1989 | (62) | (495) | (557) | 150 | 76 | (331) |
| 1990 | 178 | (495) | (317) | 150 | 76 | (91) |

Notes: 1. See Table 5 for the short-run base case surplus/deficit.
2. Reserve requirements are based on the Company's assumptions of 70% PIP phase in during 1987 and Seabrook I on-line in June 1987 (Exh. HO-157B).

Sources: Exhs. HO-9, HO-157B, and HO-157C.

TABLE 7

Siting Council Calculation of
the Risk of a Blackout in Downtown Boston

Assumptions:
1. A summer period is 120 days.
2. If load exceeds certain threshold levels and both New Boston units are out of service ("OOS"), a blackout will occur.
3. The threshold level of 2080 MW will be exceeded on 40 of the 120 summer days in 1987.
4. The threshold level of 2000 MW will be exceeded on 60 of the 120 summer days in 1988.
5. Both New Boston units will be OOS on two days during the summer period in any given year.
6. All events are independent.

Method: The calculation of blackout risk due to both New Boston generating units being OOS is based on standard probability theory for sampling without replacement. For example, if the population consists of 120 summer days, it is assumed that on two of those 120 days both New Boston units will be OOS, and it is also assumed that load will exceed the threshold blackout level on one of the 120 days, then the probability that there will not be a blackout under those conditions is estimated by the following function:

$$\text{Pr[No blackout]} = \frac{\text{No. of days no blackout expected}}{\text{Total no. of days available}}$$

$$= (118/120) = 98.3\%$$

The probability of a blackout follows as,

$$\text{Pr[Blackout]} = 1 - \text{Pr[No blackout]} = 1.7\%$$

Calculation: If it is assumed that load will exceed the threshold level of 2080 MW on 40 of the 120 days (1987 summer), the probability of no blackout becomes,

$$\text{Pr[No blackout]} = (118/120)(117/119)(116/118)...(79/81) = 44.3\%$$

and the probability of a blackout occurring is,

$$\text{Pr[Blackout in 1987 summer]} = 55.7\%$$

If it is assumed that load will exceed the threshold level of 2000 MW on 60 of the 120 days (1988 summer), the probabilities are,

$$\text{Pr[No blackout]} = (118/120)(117/119)(116/118)...(59/61) = 24.8\%$$

$$\text{Pr[Blackout in 1988 summer]} = 75.2\%$$

Source: Exh. BOS-11

TABLE 8

Boston Edison Company
Projected Effects of Demand Management

| | Annual Energy Requirements (GWh) 1986 | 1995 | Reduction in Energy Consumption (GWh) | Average Annual Compound Growth Rate 1986-1995 |
|---|---|---|---|---|
| Residential: | | | | |
| Natural Forecast | 3,001 | 3,521 | --- | 1.8% |
| With Conservation | 3,001 | 3,458 | 63 | 1.6% |
| Commercial: | | | | |
| Natural Forecast | 6,087 | 7,964 | --- | 3.0% |
| With TOUR | 6,087 | 8,012 | (48) | 3.1% |
| With Conservation | 6,087 | 7,793 | 171 | 2.8% |
| With TOUR and C&LM | 6,087 | 7,841 | 123 | 2.9% |
| Industrial: | | | | |
| Natural Forecast | 1,897 | 2,472 | --- | 3.0% |
| With TOUR | 1,897 | 2,492 | (20) | 3.1% |
| With Conservation | 1,897 | 2,404 | 68 | 2.7% |
| With TOUR and C&LM | 1,897 | 2,424 | 48 | 2.8% |
| Total Energy and Growth Rate Reduction | | | 234 | 0.17% |

| | Peak Energy Requirements (MW) 1986 | 1995 | Reduction in Peak Consumption (MW) | Average Annual Compound Growth Rate 1986-1995 |
|---|---|---|---|---|
| SUMMER: | | | | |
| Natural Forecast | 2,519 | 3,227 | --- | 2.8% |
| With TOUR | 2,519 | 3,143 | 84 | 2.5% |
| With Conservation | 2,519 | 3,069 | 158 | 2.2% |
| With Load Mngmt | 2,519 | 3,138 | 89 | 2.5% |
| With TOUR and C&LM | 2,519 | 2,980 | 247 | 1.9% |
| WINTER: | | | | |
| Natural Forecast | 2,246 | 2,980 | --- | 3.2% |
| With TOUR | 2,246 | 2,905 | 75 | 2.9% |
| With Conservation | 2,246 | 2,854 | 126 | 2.7% |
| With Load Mngmt | 2,246 | 2,934 | 46 | 3.0% |
| With TOUR and C&LM | 2,246 | 2,808 | 172 | 2.5% |

Source: Exh. HO-3, pp. E-23, F-27, G-11, and I-32; Exh. HO-128.

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently ammended by Chapter 485 of the Acts of 1971).